Portland General Electric

Distribution Interconnection Handbook

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1 Purpose and Scope

Portland General Electric Company (PGE) has prepared this document to describe the processes pertinent to distributed energy resources (DERs) seeking to interconnect to the PGE system, the technical requirements of such interconnections, and PGE's methods for evaluating the DERs compliance with the requirements. These requirements apply to:

- New DERs seeking to interconnect with the PGE system
- The ongoing operation of existing DERs on the PGE system
- Existing DERs seeking to make any changes other than minor equipment modifications as defined in OAR 860-082 (Small Generator Interconnection Rules).

In this document, DERs are defined as facilities capable of delivering electric power using generators and energy storage technologies that can be connected directly to the PGE system or connected to a host facility within the PGE system.

Facilities that are **not** covered in this document are those:

- Interconnecting to PGE's high-voltage transmission system and under the jurisdiction and requirements of the Federal Energy Regulatory Commission (FERC).[1]
- Interconnecting to the PGE system, for DERs larger than 10 megawatts (MW) in nameplate rating, and not selling electricity on a wholesale basis. Such DERs follow Oregon Standard Interconnection Procedures and Agreements Adopted for Large Qualifying Facilities (QFs) in Public Utility Commission of Oregon (OPUC) Order Number 10-132.

Technical requirements stated herein are substantially based on:

- Interconnection standards 1547-2018 and 1547.1-2021 of the Institute of Electrical and Electronics Engineers, Inc. (IEEE)
- UL 1741SB of the Underwriters Laboratory (UL)
- National Electrical Code® (for example, NFPA 70®)
- Reliability standards developed by the North American Electric Reliability Council (NERC) and Western Electric Coordinating Council (WECC)
- Good utility practices

While this document is intended as a helpful review of PGE's technical requirements, it is not a comprehensive guide to all the complexities that may arise with interconnecting or operating an individual DER on the PGE system.

Oregon Administrative Rules are regulations created by state agencies to implement Oregon law. The majority of utility regulation happens under Chapter 860 of the OAR. Within OAR chapters, there are divisions that apply to certain subjects. OAR 860-082 (small generator) covers small generator interconnection rules, OAR 860-039 (net metering) covers net metering rules, and OAR 860-088 and PGE Standards for Interconnection of Community Solar Program Projects cover Community Solar Program (CSP) rules. The applicant is required to meet all timelines in the relevant OARs unless PGE

[1] OATI OASIS.

and the applicant mutually agree on other timelines. This document does not duplicate the full descriptions of pertinent interconnection processes, rules, and timelines in the OARs noted above.

An “applicant” or “customer” refers to an entity or person that seeks to interconnect a DER to the PGE system. DER applicants are responsible for adhering to all relevant process and technical requirements for DER interconnection and operation, including applicable tariffs; federal, state, and local government laws and regulations; utility industry standards; and interconnection-related documents that applicants sign with PGE, regardless of whether such requirements are explicitly contained or referenced in this document. If there are inconsistencies between this document and federal, state, or local government laws or regulations, or between this document and tariffs filed by PGE or agreements signed with PGE, the respective laws, regulations, tariffs, or agreements control, except where PGE is taking action to protect the safety and reliability of the PGE system in accordance with good utility practice.

1.1 Overview of System Conformity, Limitations, and Upgrade Cost Requirements

PGE interconnection evaluations of proposed DERs are managed in accordance with applicable laws and regulations, IEEE standards, good utility practice, and other requirements. PGE technical screenings and studies consider issues such as short-circuit capabilities, transient voltages, reactive power requirements, stability requirements, harmonics, asset capacities, safety, operations, maintenance, and good utility practice. New facilities and upgrades are identified in the studies to maintain system design standards and safely accommodate the DER.

Proposed DERs are evaluated to determine effects on the associated PGE feeder, substation, and the connected transmission system, as well as on any affected utility system other than PGE’s. The proposed DERs must conform to the existing system limitations based on PGE’s power quality and other guidelines. If PGE’s interconnection evaluation determines that the proposed DERs impose safety, reliability, and power quality risks on PGE’s system, the applicant is responsible for the cost of PGE designing and constructing any new mitigating facilities and system upgrades.

The applicant is also responsible for the cost of maintaining and repairing any interconnection-related equipment between the DER and the point of interconnection (POI) for small generator and CSP applications or point of common coupling (PCC) for net metering applications. This includes, but is not limited to, all necessary distribution system and equipment upgrades to accommodate the proposed interconnection, as well as any corresponding communication facilities.

1.2 Overview of Applicant Responsibility for Liability, Insurance, and Easements/Rights of Way

The applicant is liable for any loss, cost claim, injury, or expense arising from any act or omission related to the performance of the interconnected DER. In addition, a small generator or CSP applicant with a DER having nameplate rating above 200 kW must obtain prudent amounts of general liability insurance in relation to the interconnection at their own expense sufficient to protect PGE or any other party that may be affected by the DER interconnection. That insurance must be maintained over the entire course of the DER interconnection agreement with PGE, and documentation of the insurance coverage must be provided annually to PGE unless otherwise specified in the interconnection agreement.

The applicant is responsible, without cost to PGE, for all easements, rights of way, and permits required for the installation and maintenance of their own DER. These may include easements for overhead or underground PGE distribution line extensions to the DER. The applicant must acquire a permit from the authority having jurisdiction (AHJ) before DER work in the right-of-way may be performed.

When an easement or right-of-way is required for the interconnection of the applicant's DER to the PGE system, the applicant may be required to obtain the easement or right-of-way, whether that easement or right-of-way is on property owned by the applicant or on property owned by an outside party and to which the applicant has rights through a lease or other legal arrangement.

1.3 Overview of Applicant Responsibility for DER Equipment

The applicant is responsible for the proper installation, operation, and maintenance of their DER equipment. A certificate of completion from PGE is not an endorsement of applicant-owned facilities nor a guarantee of performance, but only a finding that the DER can safely and reliably interconnect with the PGE system at the time the certificate of completion is issued and under the test conditions and settings in place at that time.

Moreover, the applicant is responsible for ensuring that its protection scheme is adequately protective of its DER equipment. The requirements described in this document, and the example single-line (also called "one-line") diagrams in Section 12, Example Single-Line Diagrams, are intended only to show interconnection relays that protect the PGE system, not the DER equipment itself.

More information on applicant responsibilities for their own equipment is provided in later sections of this document.

1.4 Facility Types

The types of DERs eligible to interconnect to the PGE system are solely based on FERC rules, OPUC rules, and PGE tariffs.

1.4.1 Inverter-Based Facilities

Inverter-based facilities include any direct current (dc) power supply facility that requires alternating current (ac) conversion. These include, but are not limited to, solar photovoltaic (PV) or energy storage facilities. Inverter-based facilities utilizing UL 1741 SB smart inverters are able to provide multiple functions, such as connecting to and disconnecting from the grid, generation limiting, power factor control, voltage regulation (volt-var, volt-watt, power factor, etc.), frequency response, price/temperature driven functions, ride-through functions, and load and generation following functions. As of June 1, 2024, all inverter-based facilities will be required to use IEEE 1547-2018 compliant equipment; this requirement is assured by using inverters tested to meet the UL 1741 SB requirements.

DER projects may have multiple inverters. The sum of the inverter nameplate ratings is used in rounding calculations with voltage at the location where the ground reference will be attached. For

DERs interconnecting at secondary voltage, a single ground-referencing device may prove sufficient for the combined DER nameplate rating.

1.4.2 Machine-Based Facilities

Machine-based facilities are used to convert mechanical energy into electrical power. These sources include, but are not limited to, synchronous generators and induction generators.

1.4.2.1 Synchronous Generators

Synchronous generators can be used to produce electrical energy and provide frequency response. These generators require a DC power source for startup.

1.4.2.2 Induction Generators

Induction (asynchronous) generators produce electrical energy when rotor rotation exceeds synchronous speed. To start, these generators need to draw energy from an external source. With the absence of an external energy source or a reactive supply, these generators do not possess the ability to restore electrical power to a disconnected and de-energized part of an electrical grid. These generators can be coupled with wind or small hydro turbines to produce electrical power.

1.5 Overview of Interconnection Process

This section summarizes process requirements for DERs interconnecting to the PGE system. The major steps for DERs to be successfully interconnected include the following:

- Application
- Assignment of Queue Position
- Technical Screening and/or Study
- Interconnection Agreement
- Design, Procurement, and Construction
- Commissioning, Inspections, and Witness Testing
- Operation and Maintenance

These steps are described in turn in this document.

1.5.1 Level of Service Offered for Interconnection on the Distribution System

PGE offers four options for customers interested in installing DERs that are not under FERC jurisdiction. The options are typically based on interconnection type and DER nameplate rating, but they also can be differentiated by compensation method and are briefly described below.

1.5.1.1 Net Metering

PGE offers net metering to applicants interested in offsetting their electricity consumption as an existing retail service customer of PGE. Under net metering, customers are compensated based on energy measured in kilowatt-hours (kWh) provided to the PGE system during a given billing period. The energy provided is deducted from the customer consumption prior to billing.

With net metering, residential customers can install a facility that has a generating capacity of 25 kW_{ac} or less. Non-residential customers can install a facility with a generating capacity of 2 MW_{ac} or less. Only certain technology types qualify for net metering. They are solar, battery backup systems, wind, fuel cell, hydroelectric, landfill gas, digester gas, waste, dedicated energy crops available on a renewable basis, or low-emission, nontoxic biomass based on solid organic fuels from wood, forest, or field residues.

Schedule 203 and other materials on PGE's website define net metering service in greater detail.

1.5.1.2 Small Generator Interconnection

Customers interested in installing a generating facility for the purpose of selling energy to PGE may qualify for a small generator interconnection. Under the small generator interconnection rules, customers can install DERs up to 10 MW of capacity.

If the small generator applicant wishes to sell power to PGE as a qualifying facility (QF), it must execute a Power Purchase Agreement (PPA) with PGE subject to Schedule 201, which is provided on PGE's website. The PPA may contain provisions relating to DER interconnection.

The OAR-defined small generator program described above does not apply to interconnection requests that are FERC-jurisdictional. DER applicants of small-generator-scale projects that are FERC-jurisdictional must follow applicable FERC interconnection standards. FERC-jurisdictional DER projects interconnected at the utility distribution system level are defined as those making wholesale market sales of electricity. In addition, all interconnections for new or expanded capacity for generation projects interconnected at the transmission system level are FERC-jurisdictional.

1.5.1.3 Community Solar Program

Customers seeking to install solar DERs to sell power to PGE end-user subscribers within the Community Solar Program (CSP) may apply for interconnection of DERs up to 3 MW in capacity. The interconnection requirements for CSP DERs are similar to small generator requirements, though they differ in some respects such as the possibility of joint study for applications in limited circumstances. Each CSP applicant must also execute a Community Solar Program Purchase Agreement with PGE.

1.5.1.4 Large Generator, Non-FERC Jurisdictional Interconnection

Customers seeking to install DERs larger than 10 MW and up to 20 MW that are not under FERC jurisdiction may qualify for a large generator interconnection to the PGE system on the same basis as DERs larger than 20 MW. Such customers should expect to follow Oregon Standard Interconnection Procedures and Agreements Adopted for Large Qualifying Facilities in OPUC Order Number 10-132. DER interconnection requests that are FERC-jurisdictional must follow applicable FERC interconnection standards.

Large generator interconnection requirements are not otherwise described in this document. For information regarding the Large Generator Interconnection process, refer to Attachment O in the Open Access Transmission Tariff found on PGE's OASIS page.

2 Application Submission and Initial Review

This section summarizes the process from prior to interconnection application submission through the stage at which the application is judged to have the necessary information and fees to be placed in a queue for technical review by PGE.

2.1 Pre-Application Report

Potential DER interconnection applicants, or other interested parties such as DER project developers that are evaluating the installation of a small generator or CSP interconnection, can request a pre-application report from PGE. The report is based on the proposed POI on the PGE system and contains relevant information that may be used to understand the feasibility of interconnecting a DER at the POI. Applicants may be required to sign a confidentiality agreement to obtain their pre-application report depending on the nature of the information in the report.

Consistent with Oregon Administrative Rules requiring that requestors reimburse utilities for reasonable costs associated with the reports, there is a pre-application fee of $300 per request. PGE may require up to 30 business days to complete a report.

Applicants may request a pre-application report following the described process via PGE's PowerClerk portal. Additionally, Tier 4 net metering applicants can request certain information associated with their proposed interconnection location after they submit an application. This information includes available fault current, existing peak loading on PGE distribution lines in the vicinity of their proposed DER, and the configuration of distribution lines at the proposed PCC. PGE will provide such information within three business days of the request.

2.2 Interconnection Type Tier

The interconnection type (net metering, small generator, and CSP) and DER nameplate rating dictate which interconnection application is needed. Table 1 maps the tier of application needed by interconnection type and DER capacity.

Each progressively higher tier involves more detailed technical screens or detailed studies to assess DER requirements and impacts on the PGE system and, as needed, to identify new PGE facilities and system upgrades that would allow the DER to safely and reliably interconnect. At the highest tier (Tier 4) for a net metering applicant, an impact study by PGE is required if the DER interconnection application is to advance. A facilities study may also be required. At the highest tier (Tier 4) for a small generator or CSP applicant, a combination of a feasibility study, system impact study, and/or facilities study may be required.

Table 1. Tiers of Interconnection-Based on Interconnection Type and DER Nameplate Rating

<table>
<tr><th colspan="2">Net Metering</th></tr>
<tr><td>Tier 1</td><td>Inverter-based and with an export capacity less than or equal to 25 kWac and a generation capacity less than or equal to 50 kWac.</td></tr>
<tr><td>Tier 2</td><td>Less than or equal to 2,000 kWac of generation capacity and meets the Tier 2 export capacity limits in the table below.
<table>
<tr><td>Line Voltage</td><td colspan="2">Export Capacity for Tier 2 Eligibility</td></tr>
<tr><td></td><td>Regardless of Location</td><td>On > 600 amp line and < 2.5 line miles from substation</td></tr>
<tr><td>< 5 kV</td><td>< 1 MW</td><td>< 2 MW</td></tr>
<tr><td>5 kV - 14 kV</td><td>< 2 MW</td><td>< 3 MW</td></tr>
<tr><td>15 kV – 30 kV</td><td>< 3 MW</td><td>< 4 MW</td></tr>
<tr><td>31 kV – 69 kV</td><td>< 4 MW</td><td>< 5 MW</td></tr>
</table>
</td></tr>
<tr><td>Tier 4</td><td>Less than or equal to2,000 kWac of generation capacity and does not meet Tier 2 requirements.</td></tr>
<tr><th colspan="2">Small Generator</th></tr>
<tr><td>Tier 1</td><td>Inverter based and with an export capacity less than or equal to 25 kWac and a nameplate rating less than or equal to 50 kWac with lab-tested interconnection equipment.</td></tr>
<tr><td>Tier 2</td><td>Less than or equal to 25 kWac of export capacity and does not meet Tier 1 screening requirements in Section 3.3, but does meet Tier 2 requirements;
or
Meets the export capacity limits in the table below.
<table>
<tr><td>Line Voltage</td><td colspan="2">Export Capacity for Tier 2 Eligibility</td></tr>
<tr><td></td><td>Regardless of Location</td><td>On > 600 amp line and < 2.5 line miles from substation</td></tr>
<tr><td>< 5 kV</td><td>< 1 MW</td><td>< 2 MW</td></tr>
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<tr><td>31 kV – 69 kV</td><td>< 4 MW</td><td>< 5 MW</td></tr>
</table>
Also, in all cases, must:

Use lab-tested or field-tested interconnection equipment
Be seeking interconnection to either a radial distribution circuit or a spot network distribution circuit limited to serving one customer
If the small generator is not inverter based, the small generator facility’s export capacity must be 2 MW or less.

</td></tr>
<tr><td>Tier 3</td><td>Less than or equal to 25 kWac and does not meet Tier 1 or 2 screening requirements, but does meet Tier 3 requirements;
or
Between 25 kWac and 2,000 kWac and does not meet Tier 2 screening requirements, but does meet Tier 3 requirements;
or
More than 2,000 kWac but no more than 10,000 kWac and meets Tier 3 screening requirements.
The DER must be designed not to export power beyond the point of interconnection.
Also, in all cases, must not be a synchronous machine to the extent that PGE is using high-speed reclosing with less than two seconds of interruption.</td></tr>
</table>

Tier 4	Less than or equal to 25 kWac and does not meet Tier 1, Tier 2, or Tier 3 screening requirements; or Between 25 kWac and 2,000 kWac and does not meet Tier 2 or 3 screening requirements; or More than 2,000 kWac but no more than 10,000 kWac and does not meet Tier 3 screening requirements.
Community Solar Program*	
Tier 2	Less than or equal to 2,000 kWac and meets Tier 2 screening requirements.
Tier 4	Less than or equal to 2,000 kWac and does not meet Tier 2 screening requirements; or Greater than 2,000 kWac but no more than 3,000 kWac.

* There is no Tier 1 or Tier 3 screening for CSP applicants. The lack of Tier 3 screening is because CSP DERs, by program definition, export to the PGE system and are not eligible for the non-exporting DER reviews that are defined for Tier 3.

2.3 Application Requirements

Application requirements are based on the relevant OAR. Applications are web forms in the respective net metering, small generator, and CSP PowerClerk software systems that are accessed through PGE's website.

2.3.1 Application Review

The review of an interconnection application by PGE cannot begin unless the application is satisfactorily completed. For an application to be considered completed (considered "pending completed" per OAR), the application must have all applicable fields filled out accurately and all application fees must be paid. Applications include information such as DER location; existing electric service at the location; DER equipment data such as nameplate rating, energy resource, prime mover technology, inverter, and customer-owned transformer descriptions; the specifications and operation of equipment used to limit export; and contact information for the applicant and the DER installation contractor.

In addition to completing the application, the applicant must provide required supporting documentation relevant to its particular tier, such as a single-line diagram; site plan; and generating, energy storage, and inverter device specification sheets. If the DER is a QF that FERC requires to self-certify, then the FERC "Notice of Self Certification" must be submitted with the application. For a CSP DER, the project must be pre-certified in that program in accordance with OAR 860-088-0040 and the CSP Program Implementation Manual.

2.3.2 Site Plans

Site plans should show the location of the DER along with the location of the utility meter(s) and ac disconnect(s) when required.

2.3.3 Site Control

A small generator or CSP applicant must demonstrate that it has control of the proposed DER site through ownership, a leasehold interest, or an option or other right to develop its DER at the site. An application can satisfy this requirement by using various types of documentation described in OAR 860-082-0025.

2.3.4 FEE STRUCTURE

Application fees are based on the tier of an application and the nameplate rating of the DER. Table 2 summarizes the appropriate application fees.

Table 2. Application Fee Structure Based on Interconnection Type, Level, and Tier

Net Metering	
Tier 1	No fee
Tier 2	\$50, plus \$1 per kWac of nameplate rating
Tier 4	\$100, plus \$2 per kWac of nameplate rating
Small Generator	
Tier 1	\$100
Tier 2	\$500
Tier 3	\$1000
Tier 4	\$1000
Community Solar Program	
Tier 2	\$500
Tier 4	\$1000

There are additional costs to the applicant for studies, if they are required, to assess the DER. Those costs and the associated study agreements are described later in this section.

2.3.5 INITIAL REVIEW TIMELINES

Table 3 describes the timing for PGE's review of the completeness of DER interconnection applications.

Table 3. Application Review Timeline Based on Interconnection Type, Level, and Tier

Net Metering	
Tier 1	3 business days of receipt
Tier 2	3 business days of receipt
Tier 4	3 business days of receipt
Small Generator	
Tier 1	10 business days of receipt
Tier 2	10 business days of receipt
Tier 3	10 business days of receipt
Tier 4	10 business days of receipt
Community Solar Program	
Tier 2	10 business days of receipt
Tier 4	10 business days of receipt

If the application is deemed "pending completed," it is considered complete by PGE and enters the utility's interconnection queue (see Section 2.4, Interconnection Queue).

If the application is found by PGE to be incomplete, the utility will send a list of information needed to the applicant to complete the application. For a small generator or CSP DER, the applicant has 10 business days from receipt of the note of deficiencies to provide the required information. If the applicant does not meet that timeline, the application is withdrawn by PGE. For net metering DERs, the applicant is expected to provide the required, additional information within 10 business days.

Per the OAR, an applicant with a "pending completed" application for a small generator or CSP DER must submit a new application if the applicant proposes to make any change to the small generator DER, including changes to the DER's proposed POI or to its nameplate rating, other than a minor equipment modification (as defined in the OAR and reprinted in the Glossary).

2.4 Interconnection Queue

As noted above, an application enters the interconnection queue when the application is deemed "pending completed." The queue is ranked based on the date and time that PGE receives the completed application. An application is not considered complete until the application fee has been paid.

Once an application has entered the queue, any changes to the DER other than minor equipment modifications, as defined in OAR 860-082-0015(27)(c), require the submission of a new application, thus relinquishing the current queue position. The new application will enter the queue based on the date and time it is deemed "pending completed."

A small generator or CSP application retains its original interconnection queue position if the application is resubmitted at a higher tier of screening within 10 business days of the date when the applicant receives PGE's denial of the application at a lower tier of screening. If the applicant meets that timeline, the original application fees can be used to offset the cost of the higher-tier application.

A small generator application relinquishes its small generator queue position if it subsequently applies as a CSP DER. PGE maintains separate queues for small generator and CSP applications.

A net metering application retains its queue position if the applicant resubmits the application within 30 business days of PGE's denial of its application at a lower level of screening. If a Tier 2 net metering application must be resubmitted to Tier 4, fees previously paid are applied to the Tier 4 screening of the application.

3 Interconnection Technical Screenings and Studies

This section describes technical requirements for DER interconnecting to the PGE system and PGE's methods for evaluating the DER compliance with the requirements. The requirements are the same for small generator, CSP, and net metering applicants, unless otherwise noted. The requirements listed herein provide a means to interconnect DERs to the PGE system while ensuring the safety, reliability, and power quality of the PGE system.

An interconnection application at Tier 4 may require one or more types of studies. Screening requirements reflect the screens as laid out in OAR 860-082 based on the tier of the interconnection application, as well as PGE's analysis of the proposed DER at its proposed POI or PCC on the PGE system.

Interconnection applications at lower tiers (Tiers 1, 2, and 3) are typically evaluated using structured technical screening processes that do not require full studies. If an application fails one or more technical screens at a given tier of screening, PGE will provide the applicant a report that details the review results and an executable supplemental review agreement. This screen failure report will include specific information on the reason(s) the project did not pass the screens. Following receipt of the screen failure report, the applicant can choose to request an applicant options meeting with the utility; initiate the supplemental review process discussed in Section 3.4.6, Supplemental Review, by returning the supplemental review agreement and the corresponding fee; or resubmit the application for review under Tier 4. If the application is submitted at Tier 4 with the necessary information and any additional fees required within the OAR-prescribed timeline, the application maintains its queue position and PGE reviews the application based on the requirements of the higher tier. If the applicant chooses not to request an applicant options meeting, initiate supplemental review, or resubmit at Tier 4, or the applicant fails to provide necessary information or fees within 10 business days, the application is withdrawn.

3.1 Technical Screening Summary List

The technical screens generally applied for each tier of interconnection are listed in Section 3.2, Technical Screening of Net Metering Applicants, and Section 3.3, Technical Screening for Small Generator and CSP Applicants. These lists are provided for convenience and should not be relied upon as full depictions of technical screens. These lists, where "aggregate generation capacity" impacts are identified, include existing DER capacity plus the capacity of the applicant's DER. For more detailed and comprehensive descriptions of applicable technical screens, see OAR 860-039 (net metering), OAR 860-082 (small generator), and OAR 860-088 (CSP).

The lists in Section 3.2, Technical Screening of Net Metering Applicants, are not the same as the eligibility requirements for review under various interconnection application levels and tiers, which are summarized in Table 1 of this document.

Because Tier 4 screenings typically consist of detailed studies by PGE rather than technical screens, no Tier 4 screens are listed in relevant OARs or in Section 3.2. As a result, Tier 4 is not included in Section 3.3, Technical Screening for Small Generator and CSP Applicants. CSP DERs are not eligible for Tier 1 or Tier 3 screening. Therefore, only the Tier 2 section of Section 3.3 is applicable to CSP DER.

3.2 Technical Screening of Net Metering Applicants

In accordance with the Public Utility Commission of Oregon rules set forth in OAR 860-039 (net metering), PGE screens each net metering application using the screens for the different tiers included within OAR 860-082 (small generator).

3.3 Technical Screening for Small Generator and CSP Applicants

In accordance with the Public Utility Commission of Oregon rules set forth in OAR 860-082 (small generator), PGE screens each small generator and CSP application to ensure adherence to the rules. Following are the screening requirements for DERs interconnecting to the PGE system and PGE's methods for evaluating the DER's compliance with the requirements:

3.3.1 Tier 1

- The DER interconnection must use existing PGE facilities.
- **Substation Transformer Backfeed Screen.** Where existing protective devices and equipment cannot adequately support backfeed, the aggregated export capacity on the substation transformer must be less than 80% of the relevant minimum load for the substation transformer.
- **Penetration Screen.** For interconnection to a radial distribution circuit.
  - If 12 months of minimum load data (including onsite load but not station service load served by the proposed small generator facility) are available for the line section, the aggregated export capacity on the line section is less than 90% of the relevant minimum load for all line sections bounded by automatic sectionalizing devices upstream of the proposed small generator facility;
  - If 12 months of minimum load data (including onsite load but not station service load served by the proposed small generator facility) are not available for line section, the aggregated export capacity on the circuit is less than 90% of the relevant minimum load for the feeder;
  - If minimum load data are not available for the line section or the circuit, the aggregated export capacity on the circuit must not exceed 15% of the line section annual peak load as most recently measured at the substation or calculated for the line section.
- **Network Screen.** For interconnection of a small generator facility within a spot network, the aggregate nameplate rating may not exceed 20% of the spot network anticipated minimum load. PGE may select any of the following methods to determine anticipated minimum load:
  - The spot network's measured minimum load in the previous year, if available;
  - Five percent of the spot network's maximum load in the previous year;
  - The applicant's good faith estimate, if provided; or
  - PGE's good faith estimate, if provided in writing to the applicant along with the reasons why PGE considered the other methods to estimate minimum load inadequate.
- **Single-Phase Shared Secondary Screen.** For interconnection of a small generator facility to a single-phase shared secondary line, the aggregated export capacity on the shared secondary must not exceed 65% of the transformer nameplate power rating.

- **Service Imbalance Screen.** For interconnection of a single-phase small generator facility to the center tap neutral of a 240-volt service line, the addition of the small generator facility must not create a current imbalance between the two sides of the 240-volt service line of more than 20% of the nameplate power rating of the service transformer.

3.3.2 Tier 2

- **Substation Transformer Backfeed Screen.** Where existing protective devices and equipment cannot adequately support backfeed, the aggregated export capacity on the substation transformer must be less than 80% of the relevant minimum load for the substation transformer.
- **Penetration Screen.** For interconnection to a radial distribution circuit.
  - If 12 months of minimum load data (including onsite load but not station service load served by the proposed small generator facility) are available for the line section, the aggregated export capacity on the line section must be less than 90% of the relevant minimum load for all line sections bounded by automatic sectionalizing devices upstream of the proposed small generator facility;
  - If 12 months of minimum load data (including onsite load but not station service load served by the proposed small generator facility) are not available for line section, the aggregated export capacity on the circuit is less than 90% of the relevant minimum load for the feeder;
  - If minimum load data are not available for the line section or the circuit, the aggregated export capacity on the circuit must not exceed 15% of the line section annual peak load as most recently measured at the substation or calculated for the line section.
- **Network Screen.** For interconnection of a small generator facility within a spot network, the aggregate nameplate rating may not exceed 20% of the spot network or area network's anticipated minimum load. PGE may select any of the following methods to determine anticipated minimum load:
  - The spot network's measured minimum load in the previous year, if available;
  - Five percent of the spot network's maximum load in the previous year;
  - The applicant's good faith estimate, if provided; or
  - PGE's good faith estimate if provided in writing to the applicant along with the reasons why PGE considered the other methods to estimate minimum load inadequate.
- **Fault Current Screen.** The small generator facility, aggregated with other generation on the distribution circuit, will not contribute more than 10% to the distribution circuit's maximum fault current at the point on the primary voltage distribution line nearest the point of interconnection.
- **Short-Circuit Interrupting Capability Screen.** The aggregated nameplate rating on the distribution circuit must not cause any distribution protective devices and equipment (including substation breakers, fuse cutouts, and line reclosers) or other PGE equipment on the transmission or distribution system to be exposed to fault currents exceeding 90% of the short circuit interrupting capability. The small generator facility's point of interconnection must not be located on a circuit that already exceeds 90% of the short circuit interrupting capability.
- **Transient Stability Screen.** The small generator facility's nameplate rating, in aggregate with other small generator facilities interconnected to the distribution side of a substation transformer

feeding the circuit where the small generator facility proposes to interconnect must not exceed 10 MW in an area where there are known or posted transient stability limitations to generating units located in the general electrical vicinity (for example, three or four distribution busses from the point of interconnection).

- **Line Configuration Screen.** Using Table 2 attached, determine the type of interconnection to a primary distribution line. This screen includes a review of the type of electrical service provided to the project, including line configuration and the transformer connection to limit the potential for creating overvoltages on PGE's distribution system due to a loss of ground during the operating time of any anti-islanding function.

Table 4. Interconnection Type Requirements by Primary Distribution Line Configuration

Primary Distribution Line Type	Type of Interconnection to Primary Distribution Line Required to Pass Screen
Three-phase, three-wire	Interface connection transformer high side is phase-to-phase
Three-phase, four-wire	For single phase generation, the interface connection transformer high side is phase-to-neutral; For three-phase inverter-based generation, the interface connection transformer is (1) Yg-yg, or (2) Yg-delta with a relay on the transformer high side that can detect faults; or, For three-phase rotating generation, the small generator facility high side is connected phase-to-neutral and effectively grounded.
Three-phase, four-wire, or mixed three-wire and four-wire	The public utility will extend the neutral wire to the point of interconnection and treat the small generator facility as an interconnection to a three-phase, four-wire system.

- **Single-Phase Shared Secondary Screen.** For interconnection of a small generator facility to a single-phase shared secondary line, the aggregated export capacity on the shared secondary must not exceed 65% of the transformer nameplate power rating.
- **Service Imbalance Screen.** For interconnection of a single-phase small generator facility to the center tap neutral of a 240 V service line, the addition of the small generator facility must not create a current imbalance between the two sides of the 240 V service line of more than 20% of the nameplate power rating of the service transformer.
- The interconnection of the small generator facility must not require system upgrades or interconnection facilities different from or in addition to the applicant's proposed interconnection equipment, except in the case of minor modifications with a total cost of less than $10,000.
- If PGE's distribution circuit uses high speed reclosing with less than two seconds of interruption, then the small generator facility must not be a synchronous machine. If the small generator facility is a synchronous machine, then the applicant must submit a Tier 4 application.
- **Inadvertent Export Screen.** For interconnection of a proposed small generator facility that can introduce inadvertent export, where the nameplate rating minus the export capacity is greater than 250 kW, the following inadvertent export screen is required. With a power change equal to the nameplate rating minus the export capacity, the change in voltage at the point on the medium voltage (primary) level nearest the point of interconnection does not exceed 3%. Voltage change will be estimated applying the formula shown in Figure 1.

$$\frac{(R_{SOURCE} \times \Delta P) - (X_{SOURCE} \times \Delta Q)}{V^2}$$

Where:

$$\Delta P = (\text{DER apparent power Nameplate Rating} - \text{Export Capacity}) \times PF,$$

$$\Delta Q = (\text{DER apparent power Nameplate Rating} - \text{Export Capacity}) \times \sqrt{(1 - PF^2)},$$

R_{SOURCE} is the grid resistance, X_{SOURCE} is the grid reactance, V is the grid voltage, PF is the power factor

Figure 1. Voltage Change Formula

3.3.3 Tier 3

- Tier 3 is not applicable to net metering or CSP.
- The DER must meet all Tier 2 technical screens described in Tier 2.
- The DER shall not export power beyond the POI.
- The DER shall use low forward power relays or other protection functions that prevent power flow onto the area network.
- If the DER's POI is proposed for the load side of an area network, the DER shall use lab-tested, inverter-based interconnection equipment; shall have nameplate rating that does not exceed 50 kW; and the aggregated nameplate rating on the area network must not exceed five percent of an area network's maximum load or 50 kilowatts, whichever is less.
- If the DER's POI is not on a spot network or an area network, the POI shall be on a radial distribution circuit, the DER shall have a nameplate rating that does not exceed 10 MW, the aggregate generation capacity on the circuit shall not exceed 10 MW, and the DER shall not be served by a shared transformer.

3.3.4 Tier 4

Tier 4 applications are not evaluated through the use prescribed screens. Tier 4 applications are to be reviewed using detailed engineering studies as described below and as included in OAR 860-039-0040 and OAR 860-082-0060.

3.4 Study Types

Depending on the tier of the interconnection application, the DER's interconnection applications may be reviewed under any or all of the progressively more detailed study types described below.

- Feasibility Study (not applicable to CSP applications)
- System Impact Study (terminology for small generator and CSP applications) or Impact Study (terminology for net metering applications)
- Facilities Study

For each study that is required, PGE notifies the applicant and provides a study agreement. The agreement outlines what information is reviewed and the cost of the study. The study fees are based on the number of engineering hours PGE estimates are needed to conduct the study. When studies are required, the applicant must sign a study agreement before a study can be completed and its application can advance. An applicant wishing to withdraw its application can decline to sign a study agreement.

Not all studies are required for every Tier 4 application. PGE and an applicant may agree to waive the requirement for a scoping meeting, a system impact study, or the facility Study. The applicant may waive the requirement for a feasibility study.

Each study can take a considerable amount of time and effort depending on the type of interconnection, the queue position of the proposed DER in relation to other DERs at similar locations on the PGE system, DER capacity, and the extent and complexity of potential impacts on the PGE system and any affected systems.

At the conclusion of each study, PGE issues a report to the applicant outlining the results. The report may contain a summary of the study scope, study assumptions, requirements (for example, protection enhancements), PGE system modifications necessary for interconnection, the applicant's and PGE's respective responsibilities for implementing the requirements and modifications, estimated applicant costs for the requirements and modifications, and an estimated schedule for the design, procurement, and construction of the requirements and modifications.

When conducting studies, PGE considers all existing energized DERs, as well as DERs ahead of the applicant's project in queue at the feeder and substation associated with the applicant's planned POI or PCC. DERs interconnected with affected systems of other utilities are also considered if they may impact the applicant's interconnection request. Doing so allows PGE to model system impacts in a comprehensive manner accounting for the cumulative impacts of DERs on relevant portions of the PGE system.

PGE studies DERs serially at each POI or PCC (feeder or substation). There is currently no joint (or group) study process for net metering or small generator applicants. This means that each DER incurs the PGE interconnection facilities and system upgrade costs necessary for the safe and reliable integration and operation of the DER, regardless of the effects of those costs on other DERs with a lower queue position at the same POI or PCC. There is a joint study process for CSP applications submitted by the same organization that are back-to-back in the queue on the same feeder, whereby each CSP DER project is allocated the interconnection costs for system upgrades based on its proportional capacity.

Timing related to each study type is listed in the following sections. Applicants should note that there are no OAR-prescribed timelines for PGE's completion of the studies themselves, except for the net metering impact study. However, there are prescribed timelines in several instances for the utility to provide study agreements (contracts authorizing the utility to perform the study) to applicants and for applicants to return signed study agreements to the utility. If applicants do not meet timelines for returning signed study agreements, their applications are withdrawn.

For small generator and CSP applications, there is an option for a scoping meeting between PGE and the applicant to determine the types of studies that may be required for the application. The applicant and PGE can jointly decide to forego the scoping meeting so that the application can proceed directly and more quickly to PGE's review. Small generator applicants whose DER does not pass technical screens should expect that the study process will begin with the feasibility study. CSP applicants whose DER does not pass technical screens should expect that the study process will begin with the system impact study.

Following are the study types and a description for each interconnection program.

3.4.1 Net Metering Study Types

- Impact Study
  - Within 7 business days of completion of the application, PGE provides the applicant with the study agreement.
  - Within 30 calendar days of receiving a signed study agreement and payment of the good faith estimated study cost, PGE determines if only minor modifications are needed to accommodate interconnection of the DER, or if substantial modifications are needed and if systems of other utilities will be affected.
- Facilities Study
  - There are no OAR-prescribed timelines.

3.4.2 Small Generator and CSP Study Types

- Feasibility Study (not applicable to CSP DER).
  - Within 5 business days of a scoping meeting, PGE provides study agreement to the applicant.
  - Within 15 business days of receipt of the agreement, the applicant signs.
  - The timeline for the completion of the study will be included within the study agreement.
  - Within 5 business days of completion, PGE provides the applicant with the study.
- System Impact Study
  - Within 5 business days of the scoping meeting (CSP DER) or the later of a scoping meeting or completion of a feasibility study for the DER (small generator DER), PGE provides the applicant with the study agreement.
  - Within 15 business days of receipt, the applicant signs the agreement.
  - The timeline for the completion of the study will be included within the study agreement.
  - Within 5 business days of completion, PGE provides the applicant with the study.
- Facilities Study
  - Within 5 business days of the later of a scoping meeting or completion of a system impact study for the DER, PGE provides the applicant with the study agreement.
  - Within 15 business days of receipt, the applicant signs the agreement.
  - The timeline for the completion of the study will be included within the study agreement.

PGE’s ability to deliver study results on a timely basis is dependent on applicants providing accurate, timely information and responses to questions from PGE that may arise while conducting studies. Additionally, PGE studies DERs in a serial manner. With that said, when a delay occurs during the study process for a DER higher in the queue at a given feeder or substation, the delay could potentially have downstream delays of studies and results for a DER lower in the queue at the same location on PGE’s system. Also, when higher-queued projects are withdrawn, there can be down-queue impacts necessitating restudies and causing additional delays.

The study costs are based upon:

- The scope of work in the respective study agreements
- PGE’s estimate of the number of engineering hours needed to complete the study
- Consistency with the OAR maximum hourly utility labor cost

In some cases, additional studies are necessary if the proposed DER may affect distribution or transmission systems of PGE or utilities other than PGE.

Additional information on study requirements for each interconnection tier is provided below and in OAR 860-039 (net metering) and OAR 860-082 (small generator).

3.4.3 Feasibility Study

This type of study is only applicable to small generator DER applications. There is no feasibility study in the OAR for net metering applications or CSP applications.

The feasibility study provides an initial review of potential adverse impacts of interconnecting the proposed DER on the PGE system or other affected utility systems. As a result, the feasibility study provides the customer with baseline requirements needed for interconnection of the DER as well as non-binding, initial cost estimates and timelines for implementing that scope.

Due to the preliminary nature of the feasibility study, the band of uncertainty on cost and schedule estimates may be wide. The timeline may provide basic information regarding design, procurement, and construction.

If PGE concludes that neither a system impact study nor a facilities study is required, the utility will provide an interconnection agreement for the applicant’s review and signature within 15 business days of completing the feasibility study as long as the application meets other OAR interconnection review criteria, and no new interconnection facilities or system upgrades are needed beyond those identified on the DER application. If PGE identifies only minor modifications (facilities or upgrades) are needed to safely and reliably interconnect the proposed DER, but neither system impact nor facilities studies are needed, the utility will provide an interconnection agreement for the applicant’s review and signature within 15 business days of the applicant’s agreement to pay for minor modifications identified.

3.4.4 Impact Study or System Impact Study

If any adverse system impacts are found from the feasibility study (or if the applicant moves directly from the scoping meeting to a system impact study), then a system impact study for a small generator or CSP DER must be conducted to identify and detail impacts associated with the POI designated by the applicant. The system impact study builds upon PGE’s feasibility study analysis and evaluates adverse impacts to the PGE system and any other affected utility systems. This study reviews possible impacts through analyses including, but not limited to:

- Short Circuit
- Stability
- Power flow
- Voltage drop and flicker

- Protection and set point coordination
- Grounding

The system impact study may also document fault-interrupting equipment with short circuit capability limits that may be exceeded as a result of interconnecting the proposed DER.

The system impact study will contain a good faith, non-binding estimate of the costs that the applicant must pay for new interconnection facilities and system upgrades needed to accommodate the DER safely and reliably on the PGE system as well as a good faith, non-binding estimate of the timeline for designing, procuring, and constructing the necessary facilities and upgrades.

If PGE concludes that no new facilities nor system upgrades are required, the utility will provide an interconnection agreement for the applicant's review and signature within 15 business days of completing the system impact study, as long as the application meets other OAR interconnection review criteria and no new interconnection facilities or system upgrades are needed beyond those identified on the DER application. However, if PGE identifies that only minor equipment modifications (facilities or upgrades) are needed to interconnect the proposed DER safely and reliably, and a facilities study is not needed, the utility will provide an interconnection agreement for the applicant's review and signature within 15 business days of the applicant's agreement to pay for the minor modifications.

The impact study for net metering applicants is similar in scope and purpose to the system impact study described above and emphasizes power flows, utility protective devices, and control requirements. Within seven business days after receiving a complete Tier 4 application, PGE will provide an impact study agreement to the applicant. After the applicant signs the impact study agreement and pays the utility's good faith estimate of the study cost, PGE will notify the applicant within 30 calendar days of whether only minor modifications are needed to accommodate the applicant's DER or whether substantial modifications are needed, and if any other utility's systems may be affected by the new DER.

If substantial modifications are identified by PGE during the impact study process, the utility will provide a non-binding, good faith estimate of those modification costs and offer to conduct a facilities study (at the applicant's additional expense) to identify specific equipment that comprise the substantial modifications. More information on the impact study is available in OAR 860-039-0040.

3.4.5 Facilities Study

For small generator or CSP applicants, if PGE determines a new interconnection facilities or system upgrades beyond minor equipment modifications are necessary, or if the applicant moves directly from the scoping meeting to a facilities study, then a Facilities Study must be performed.

The facilities study builds upon prior studies and provides more precise identification of the new interconnection facilities and system upgrades needed to accommodate the DER interconnection based on further analysis and preliminary design activities and often involves a visit by PGE staff to the proposed DER site. The facilities study may also contain a delineation of applicant versus PGE roles and responsibilities with regards to new facilities and system upgrades. Since the facilities study is a thorough review, PGE may identify new requirements or modified requirements compared to earlier studies of the DER.

Like the system impact study, the facilities study contains good faith, non-binding estimates of interconnection costs and the timeline for designing, procuring, and constructing the necessary facilities and upgrades. Those costs and schedules are more refined estimates than in the system impact study.

The applicant has 15 business days from its receipt of the facilities study to agree to pay the costs identified within the study. If the applicant agrees, it will receive an interconnection agreement for review and signature within 5 business days of agreeing to pay the costs.

For net metering applicants, the facilities study is similar in scope and purpose to the requirements described above. Applicants must execute the facilities study agreement and pay the estimated cost of the study before PGE commences its facilities study. More information on the facilities study for net metering applicants is available in OAR 860-039-0040.

3.4.6 Supplemental Review

If a proposed DER interconnection fails to pass the technical screens of the tier under which it initially applied, the applicant has the option to request the utility complete a supplemental review of the proposed facility. During the supplemental review, the utility will evaluate an additional set of screens to determine whether the DER can interconnect without impacting the safety and reliability of the distribution system.

The applicant will receive an executable supplemental review agreement when they receive the tier screening results report. To initiate the supplemental review, the applicant must submit a signed supplemental review agreement and the supplemental review fee of $1,000.00 within 10 business days of receiving the agreement.

PGE has 20 business days to complete the supplemental review and notify the applicant of the results. The notification will include a written report of the analysis and the data underlying PGE’s determination.

In accordance with the Public Utility Commission of Oregon rules set forth in OAR 860-082-0063 PGE will review the following screens to determine the requirements for the DER to interconnect to the PGE system.

3.4.6.1 Supplemental Review Penetration Screen

- Where 12 months of line section minimum load data (including onsite load, but not station service load served by the proposed small generator facility) are available, can be calculated, can be estimated from existing data, or can be determined from a power flow model, the aggregate export capacity on the feeder or line section must be less than 100% of the relevant minimum load on the feeder. If minimum load data are not available, or cannot be calculated, estimated, or determined, the aggregated export capacity on the line section must be less than 30% of the peak load for all line sections bounded by automatic sectionalizing devices upstream of the proposed project.
  - Load that is co-located with load-following, non-exporting, or export-limited projects should be appropriately accounted for. PGE may take the impacts of non-export or export limited generation on the calculation of daytime minimum load when evaluating potential system impacts.

- PGE will not consider as part of the aggregate export capacity for purposes of this screen the export capacity of generators known to be already reflected in the minimum load data, including combined heat and power (CHP) facility capacity.

3.4.6.2 Voltage and Power Quality Screen

- In aggregate with existing generation on the line section:
  - The voltage regulation on the line section can be maintained in compliance with relevant requirements under all system conditions.
  - The voltage fluctuation is within acceptable limits as defined by IEEE 1547.
  - The harmonic levels meet IEEE 1547 limits at the point of interconnection.

3.4.6.3 Substation Transformer Backfeed Screen

- Where existing protective devices and equipment cannot adequately support backfeed the aggregated export capacity on the substation transformer must be less than 80% of the relevant minimum load for the substation transformer.

3.4.6.4 Supplemental Grounding Screen

- If the project failed the Line Configuration Screen, apply the Supplemental Grounding Screen in the following paragraphs 1–3. If the project limits export pursuant to OAR 860-082-0033, the export capacity must be included in any analysis including power flow simulations.
  1. For projects with a rotating machine, if effective grounding is maintained, the project passes the screen.
  2. For projects with a three-phase inverter, apply one of the following screens:
     - If the line-to-neutral connected load on the feeder or line section is greater than 33% of peak load on the feeder or line-section, the project passes the screen.
     - If using a supplemental grounding software tool:
       - If the tool determines that supplemental grounding is not required to maintain effective grounding, the project passes this screen.
       - If the tool determines that supplemental grounding is required, the applicant must agree to modify the project to include supplemental grounding. If the applicant does not agree to modify the project, the project fails this screen.
  3. If using detailed hosting capacity analysis that incorporates evaluation of temporary overvoltage risk for inverters, the project passes the screen if the nameplate rating of the project is below the available hosting capacity at the point of interconnection.

3.4.6.5 Safety and Reliability Screen

- The location of the proposed small generator facility and the aggregate export capacity on the line section do not create impacts to safety or reliability that cannot be adequately addressed without application of the study process. If the project limits export pursuant to OAR 860-082-0033, the export capacity must be included in any analysis, including power flow simulations, except when assessing fault current contribution. To assess fault current contribution, the analysis must use the rated fault current; for example, the applicant may provide manufacturer test data (pursuant to the fault current test described in IEEE 1547.1-2020 clause 5.18) showing that the fault current is independent of the nameplate rating. PGE may consider the following factors and others in determining potential impacts to safety and reliability in applying this screen:

- Whether the line section has significant minimum loading levels dominated by a small number of customers (i.e., several large commercial customers)
- Whether the loading along the line section is uniform or even
- Whether the project is located in close proximity to the substation (i.e., less than 2.5 electrical circuit miles), and whether the line section from the substation to the point of interconnection is a mainline rated for normal and emergency ampacity
- Whether the project incorporates an adjustable time delay function to prevent reconnection of the generator to the system until system voltage and frequency are within normal limits for a prescribed time
- Whether operational flexibility is reduced by the project, such that transfer of the line section(s) of the project to a neighboring distribution circuit/substation may trigger overloads or voltage issues
- Whether the project employs equipment or systems certified by a recognized standards organization to address technical issues such as, but not limited to, islanding, reverse power flow, or voltage quality

▪ If the DER interconnection passes the supplemental screens, the application will be approved, and PGE will provide the applicant an executed Interconnection Agreement.

3.4.7 Studies Required for Affected Systems

If the proposed DER interconnection may affect other utility systems, the affected utilities may require their own studies beyond those described above before the DER can advance in the PGE interconnection process. PGE will coordinate with other utilities so that they may perform such studies; however, PGE is not responsible for the cost, timing, or the work necessary for affected utilities to perform their studies. The applicant must contract with any affected systems to perform such studies and agree to pay associated costs before the studies are initiated. An applicant’s ability to successfully interconnect to PGE requires successful demonstration that all issues identified by “affected systems” have been successfully mitigated or otherwise addressed to the satisfaction of the affected system.

3.5 Overarching Interconnection Study Concepts

This section describes four concepts that PGE applies across its interconnection studies of DERs. This information is provided for applicants and other interested parties to gain insights into PGE’s methods to better prepare their applications and understand the rationale for decisions made by PGE to preserve the safety and reliability of the PGE system. However, this document is not a comprehensive description of PGE’s study methods.

Depending on the interconnection tier of the proposed DER as well as the studies the DER undergoes, some of the methodologies described below may not apply to a specific DER. However, the general methodologies apply to the majority of small generator and CSP interconnection applications, and to aspects of Tier 2 and Tier 4 net metering applications.

3.5.1 Additional DERs Associated with the POI or PCC

PGE models its electrical distribution system with the presence of the applicant's proposed DER in addition to the following:

- Existing DERs (possessing certificates of completion) at the same feeder or substation location as the proposed DER.
- Proposed DERs higher in the interconnection queue at the same feeder or substation as the applicant's proposed DER (for example, DERs that have not yet received a certificate of completion but have completed interconnection applications before the proposed DER application was complete).
- DERs on any affected systems of other utilities. These include both inverter-based and machine-based DER.

3.5.2 Peak (or Heavy) Load

A peak load condition is defined as the highest coincidental hourly load condition for a group of feeders served from the same substation transformer during a season when load is at its highest level. Load conditions are limited to daytime hours for studying DER that are strictly solar photovoltaic. For other forms of DER generation, such as battery systems, all 24 hours in a day are considered for peak loading.

PGE uses hourly circuit data recorded through supervisory control and data acquisition (SCADA) systems to determine the applicable peak load for its interconnection studies. For peak load conditions, the highest coincidental system load is selected and compared to corresponding weather conditions and system configuration. For this reason, 18 to 24 months of feeder load data may be evaluated to avoid anomalies in a single year's load data due to potential abnormal circuit configurations or atypical seasonal peak loads. Peak load scenarios are finalized after weather conditions and system configuration are reviewed. PGE then applies the selected feeder loads for study of the proposed DER.

3.5.3 Minimum (or Light) Load

A minimum load condition is defined as the lowest coincidental hourly load condition for a grouping of feeders served from the same substation transformer during a season when load is at its lowest level. Load conditions are limited to daytime hours for studying DER that are strictly solar photovoltaic. For other forms of DER generation, such as battery systems that are not dependent on the sun for generation, all 24 hours in a day are considered for minimum loading.

PGE uses hourly circuit data recorded through SCADA to determine the applicable minimum load for its interconnection studies. For minimum load conditions, the lowest coincidental system load is selected and compared to corresponding weather conditions and system configuration. For this reason, 18 to 24 months of feeder load data may be evaluated to avoid anomalies in a single year's load data due to potential abnormal circuit configurations or atypical seasonal light loads.

Light load scenarios are finalized after weather conditions and system configuration are reviewed. PGE then applies the selected feeder loads for study of the proposed DER. Note that during DER studies, PGE performs contingency analysis to determine distribution equipment/conductor limitations during a lost load scenario. The purpose of the contingency analysis is to analyze various lost load scenarios. If a fault happens on a feeder and a protective device (fuse, recloser, etc.) opens, this results in lost load. If generation is still online (in an area not impacted by the fault), reverse power flow from the generation would suddenly increase (since it is no longer offset by the lost load). This could result in an overload condition that could negatively impact customer or utility equipment if the lost load scenario is not analyzed during the study.

3.5.4 Limited Export or Non-Export Requirements

A DER facility may be designed to minimize or prohibit the transfer of power from the DER to the utility. In situations where the DER will limit export, the utility will take into consideration this limitation when evaluating the impacts of the DER to the system. To prevent impacts on system safety and reliability, the DER facility must use a configuration or operating mode that complies with the requirements in OAR 860-082-0033 and discussed below. The export capacity specified by the applicant will subsequently be included as a limitation in the interconnection agreement.

3.5.4.1 Export Control Methods for Non-Exporting Small Generator Facility

- **Reverse Power Protection (Device 32R):** To limit export of power across the point of interconnection, a reverse power protective function is implemented using a utility grade protective relay. The default setting for this protective function is 0.1% (export) of the service transformer's nominal base nameplate power rating, with a maximum 2.0 second time delay to limit inadvertent export. When a project is located on a circuit using high-speed reclosing, PGE may require a maximum delay of less than 2.0 seconds to facilitate the reclosing safely.
  - When a project is located on a circuit using high-speed reclosing, the project must be capable of taking the generation offline within 0.1 seconds to coordinate reclosing timing with the tripping speed of affected distributed energy resources in an effort to avoid equipment damage and prevent unacceptable stresses or disturbances on the system. At this time, there are no commercially available inverters that are UL certified to take the generation offline within 0.1 seconds and able to detect fault conditions on the high side of the step-up transformer, and therefore no inverter specifications or options will satisfy the requirement without the need for additional equipment. As inverter technologies advance and as PGE periodically reviews and updates this handbook, PGE will assess whether inverter specifications have advanced to the point where an inverter setting or option may satisfy the requirement to take the generation offline within 0.1 seconds. Until that time, projects seeking to interconnect to a circuit using high-speed reclosing will be required to install protective equipment. The specific equipment that will be required must be assessed on a case-by-case basis, but can include protective relays, reclosers, and/or direct transfer trip.
- **Minimum Power Protection (Device 32F):** To limit export of power across the point of interconnection, a minimum import protective function is implemented utilizing a utility grade protective relay. The default setting for this protective function is 5% (import) of the small generator facility's total nameplate rating, with a maximum 2.0 second time delay to limit inadvertent export.

When a project is located on a circuit using high-speed reclosing, PGE may require a maximum delay of less than 2.0 seconds to facilitate the reclosing safely.

- When a project is located on a circuit using high-speed reclosing, the project must be capable of taking the generation offline within 0.1 seconds to coordinate reclosing timing with the tripping speed of affected distributed energy resources in an effort to avoid equipment damage and prevent unacceptable stresses or disturbances on the system. At this time, there are no commercially available inverters that are UL certified to take the generation offline within 0.1 seconds and able to detect fault conditions on the high side of the step-up transformer, and therefore no inverter specifications or options will satisfy the requirement without the need for additional equipment. As inverter technologies advance and as PGE periodically reviews and updates this handbook, PGE will assess whether inverter specifications have advanced to the point where an inverter setting or option may satisfy the requirement to take the generation offline within 0.1 seconds. Until that time, projects seeking to interconnect to a circuit using high-speed reclosing will be required to install protective equipment. The specific equipment that will be required must be assessed on a case-by-case basis, but can include protective relays, reclosers, and/or direct transfer trip.

- **Relative distributed energy resource rating:** This option requires the small generator facility's nameplate rating to be so small in comparison to its host facility's minimum load that the use of additional protective functions is not required to ensure that power will not be exported to the electric distribution system. This option requires the small generator facility's nameplate rating to be no greater than 50% of the interconnection customer's verifiable minimum host load during relevant hours over the past 12 months. This option is not available for interconnections to area networks or spot networks.

3.5.4.2 Export Control Methods for Limited-Export Small Generator Facility

- **Directional Power Protection (Device 32):** To limit export of power across the point of interconnection, a directional power protective function is implemented using a utility grade protective relay. The default setting for this protective function is to be the export capacity value, with a maximum 2.0 second time delay to limit inadvertent export. When a project is located on a circuit using high-speed reclosing, PGE may require a maximum delay of less than 2.0 seconds to facilitate the reclosing safely.
  - When a project is located on a circuit using high-speed reclosing, the project must be capable of taking the generation offline within 0.1 seconds to coordinate reclosing timing with the tripping speed of affected distributed energy resources in an effort to avoid equipment damage and prevent unacceptable stresses or disturbances on the system. At this time, there are no commercially available inverters that are UL certified to take the generation offline within 0.1 seconds and able to detect fault conditions on the high side of the step-up transformer, and therefore no inverter specifications or options will satisfy the requirement without the need for additional equipment. As inverter technologies advance and as PGE periodically reviews and updates this handbook, PGE will assess whether inverter specifications have advanced to the point where an inverter setting or option may satisfy the requirement to take the generation offline within 0.1 seconds. Until that time, projects seeking to interconnect to a circuit using high-speed reclosing will be required to install protective equipment. The specific equipment that will be required must be assessed on a case-by-case basis, but can include protective relays, reclosers, and/or direct transfer trip.

- **Configured Power Rating:** A reduced output power rating utilizing the power rating configuration setting may be used to ensure the small generator facility does not generate power beyond a certain value lower than the nameplate rating. The configuration setting corresponds to the active or apparent power ratings in Table 28 of IEEE 1547-2018, as described in subclause 10.4. A local small generator facility communication interface is not required to utilize the configuration setting as long as it can be set by other means. The reduced power rating may be indicated by means of a nameplate rating replacement, a supplemental adhesive nameplate rating tag to indicate the reduced nameplate rating, or a signed attestation from the customer confirming the reduced capacity.

3.5.4.3 Export Control Methods for Non-Exporting Small Generator Facility or Limited Export Small Generator Facility

- **Certified Power Control Systems:** Small generator facility may use certified power control systems to limit export. Small generator facility utilizing this option must use a power control system and inverter certified per UL 1741 by a nationally recognized testing laboratory (NRTL) with a maximum open loop response time of no more than 30 seconds to limit inadvertent export. NRTL testing to the UL Power Control System Certification Requirement Decision must be accepted until similar test procedures for power control systems are included in a standard. This option is not available for interconnections to area networks or spot networks.
- **Agreed-upon Means:** Small generator facility may be designed with other control systems and/or protective functions to limit export and inadvertent export if mutual agreement is reached with PGE. The limits may be based on technical limitations of the interconnection customer's equipment or the electric distribution system equipment. To ensure inadvertent export remains within mutually agreed-upon limits, the interconnection customer may use an uncertified power control system, an internal transfer relay, energy management system, or other customer facility hardware or software if approved by PGE.

When proposing to limit or prevent export from the DER facility with one of the approved methods, PGE will need to review the methods and the operation of the control device. In order to conduct that review, additional information will be required from the applicant at the time of submission. The following documentation shall be submitted as an attachment with the Interconnection Application:

- Manufacturer and model of the device or power control system, or the components that make up the system
- The technical specifications of the devices or power control systems
- A description of the operating modes, services, and any specific settings that are enabled, and how the hardware/software present in the design is used to accomplish the goals of the mode being used
- A description of how the operating modes and services not being enabled are locked down to prevent unintentional enabling
- Additional information that may be requested by the utility to clarify the operation of the device or power control system

3.5.4.4 Export Control Methods with High Speed Reclosing

All PGE overhead feeders use high speed reclosing. A high speed reclose only has a six cycle open interval; thus, the generator needs cut off the inadvertent export before the feeder breaker closes back in. In order to accomplish this, certain characteristics are required:

- **Primary Metering:** The required relay on the high side of the transformer as described in section 8.6 can be used to meet this requirement
- **Non-Primary Metering:** The inverter must be UL PCS certified with settings to limit or prevent export. If the inverter does not meet this requirement, then a reverse power relay must be installed.

3.6 Interconnection Study Methodologies and Requirements

PGE applies both "base case" and "system upgrade" scenarios in its study process. The "base case" scenarios below refer to the PGE system as presently configured, with the addition of higher-queued DERs and their associated upgrades implemented. The "system upgrade" scenarios include the new interconnection facility and system upgrades needed to accommodate the proposed DER on the feeder and substation portions of the PGE system.

PGE analyzes DER impacts at times of peak loading and minimum loading on the PGE feeders served by substations associated with the proposed DERs per Section 3.5, Overarching Interconnection Study Concepts.

The specific scenarios analyzed include:

- Peak Loading Period
  - Base case with the proposed DER(s) offline (for example, due to unavailability)
  - Base case with the proposed DER(s) in service (for example, online)
  - New interconnection facilities and system upgrades with the proposed DER(s) offline
  - New interconnection facilities and system upgrades with the proposed DER(s) in service
- Light Loading Period
  - Base case with the proposed DER(s) offline
  - Base case with the proposed DER(s) in service
  - New interconnection facilities and system upgrades with the proposed DER(s) offline
  - New interconnection facilities and system upgrades with the proposed DER(s) in service

For study purposes, the proposed DER(s) is simulated with a default unity power factor and operating at full nameplate or proposed export capacity in conjunction with all additional DERs associated with the POI or PCC per Section 3.5.1, Additional DERs Associated with the POI or PCC. Alternate power factors can be modeled if mutually agreed upon by PGE and the applicant.

The following are monitored iteratively during the interconnection studies:

- **Equipment and Conductor Loading**—Conductor loading is evaluated to ensure that (mainline) feeder load does not exceed 80% of conductor and associated equipment normal load level ampacity ratings, which are based on peak loading conditions. The analysis simulates all DERs associated with the POI or PCC per Section 3.5.1, Additional DERs Associated with the POI or PCC.

- **Fault Current**—A fault current profile is simulated to ensure that the withstand ratings of distribution equipment, including but not limited to: feeder breakers, reclosers, regulators, switches, and fuses are not exceeded. The analysis is completed such that all installed and proposed DERs on the feeders served from the same substation, and any DERs on affected systems of other utilities, come in service and go offline in sync and are evaluated at equipment locations up to and including the corresponding feeder breaker. Fault current is evaluated at the POI or PCC and at equipment locations up to and including the corresponding feeder breaker.
- **Reverse Flow**—Backfeed from the proposed DER into the PGE system is simulated for peak and light loading conditions to ensure compliance with voltage and protection equipment requirements.
- **Voltage Flicker**—According to IEEE 1547-2018, DER shall not create objectionable flicker for other customers.
- **Voltage Imbalance**—Phase voltages are monitored to ensure that there is no risk of impending energy management system alarms or nuisance tripping at the feeder breaker level due to phase imbalance. The steady-state voltage imbalance shall not exceed 3.0%, consistent with American National Standards Institute (ANSI) C84.1-2016 (Electric Power Systems and Equipment – Voltage Ratings [60 Hz]).
- **Voltage Profile**—A voltage profile provides measurements of voltage at every location on the interconnected feeder and is used to ensure that the proposed DER does not violate any voltage or any power quality requirements per ANSI C84.1-2016 Range A.

If one or more power system criteria violations exist in the study modeling, PGE will attempt to mitigate the system violations without requiring the proposed DER to curtail its active power output.

3.6.1 Power Flow and Voltage Stability

Absolute voltage levels and/or voltage imbalances may require upgrades to conductors, modifications to the PGE system single-phase or two-phase taplines (with load balance considerations), and/or the addition of voltage regulators or capacitors.

PGE analyzes potential voltage and loading on the PGE system due to impacts from the proposed DER. PGE's simulation analysis includes multiple scenarios to ensure that the proposed DER does not pose any violations to the PGE system. PGE's power quality guidelines for proposed DERs are established in PGE design standards, ANSI C84.1-2016, and the most recent versions of IEEE 141-1993 (Recommended Practice for Electric Power Distribution for Industrial Plants), IEEE 519-2014 (Recommended Practice and Requirements for Harmonic Control in Electric Power Systems), and IEEE 1453-2015 (Recommended Practice for the Analysis of Fluctuating Installations on Power Systems).

If the proposed DER causes reverse power flow through any existing voltage regulation bank and the appropriate voltage regulator controls are not capable of accommodating this reverse power flow, then the voltage regulation bank shall be replaced with new voltage regulators. All new voltage regulators will have microprocessor controls capable of bidirectional and co-generation settings. Retrofitting existing voltage regulation banks with microprocessor controls is labor intensive and not cost effective.

The requirement to include bidirectional and co-generation settings on voltage regulator equipment is necessary to ensure that neighboring customers' service voltage does not stray from the acceptable ±5% voltage range under steady-state conditions, per ANSI C84.1-2016.

Voltage sensing and time delay relays may also be required to prevent excessive voltage regulator operations due to temporary voltage swings caused by the DER. The requirement to prevent excessive operations due to temporary voltage swings is largely driven by the need to reduce potential impacts to equipment life as a result of more frequent mechanical operations and subsequent wear and tear under the presence of local intermittent DER output. These concerns with equipment life extend to both mid-line voltage regulation equipment and upstream equipment, such as substation load tap changers (LTCs) or substation feeder regulators.

3.6.2 Conductor Capabilities

To ensure that no system equipment is damaged, PGE evaluates interconnecting DERs at full capacity while the surrounding load is modeled according to minimum load data (daytime for strictly PV systems). Some generation and load scenarios can create significant reverse current flow onto the PGE system. PGE's planning criterion for conductor loading during reverse power flow is 80% of rating which helps maintain adequate contingency margin for emergency situations thereby reserving operational flexibility. When the reverse current exceeds 80% of the rating of existing conductors, a primary feeder reconductor is required. PGE reviews such potential conductor or equipment loading violations accordingly.

Appropriate conductor and equipment upgrades are identified and quantified. For conductors and other equipment, the size, length, type, and thermal rating of the proposed upgraded materials is determined by PGE. Any additional actions that are necessary to accommodate conductor or other equipment upgrades (such as easements for anchors or pole relocations, or the need to upgrade from a single-phase or open-delta service to a three-phase service) are also identified.

3.6.3 Distribution Protection Requirements

PGE reviews the proposed DER's impact on existing protection equipment (including breakers, fuses, and reclosers) as part of the study process. In the event of a fault or service interruption on the PGE system, a circuit breaker, fuse, or recloser operates, opens, and isolates the fault to prevent and limit the damage to both PGE-owned and customer-owned equipment.

3.6.3.1 Hot Line Indication (for Hot Line Blocking)

PGE performs a high-level review of feeder and substation loading to determine the protection requirements based on the following guidelines using aggregate DERs on the associated feeder.

For inverter-based DERs:

- Up to 90% minimum load requires no extra protection.
- Above 90% minimum load requires hot line indication. On feeders with reclosing, the hot line indication is used to do hot line blocking.
  - A single feeder transformer up to 80% minimum load requires no extra protection. Above 80%, minimum load hot line indication is required.

For machine-based DERs, hot line indication is always used. On feeders with reclosing, hot line indication is used to do hot line blocking. Additionally, transfer trip is needed if either:

- The station does not have SCADA, and aggregate machine-based DERs exceed 1/6 of the minimum load on the feeder
- Aggregate machine-based DERs exceed 1/3 of the minimum load on the feeder

If the DER capacity can exceed loading of the station transformer (can backfeed onto the PGE transmission system) for inverter- or machine-based DERs, additional analysis is performed by PGE.

3.6.3.2 Circuit Reclosers

An electronic recloser, instead of a fuse, may be required by PGE to allow for effective coordination with other protective devices to isolate the PGE system more effectively during unplanned power quality or reliability events, and speed up restoration of service. On the PGE system, fuses are limited to tapline/service transformer load sizes and do not have voltage sensing capability.

If a recloser is required, it must meet all the following conditions:

- Be independently pole-mounted
- Have the ability to operate as a recloser, as a switch, or as a sectionalizer, and automatically change between these three functions
- Work remotely
- Be capable of both three-phase and single-phase tripping and lockout
- Be capable of hot line indication
- Be capable of Mirrored Bits Transfer Trip (MBTT)

If a recloser is not present, a PGE line crew may be required to manually close the breaker or fuse to restore power flow. If a recloser is present and the event triggering the fault or service interruption is temporary, the recloser closes after a set time delay and remains closed. As a result, inverter-based DERs can often come back online much more quickly with a recloser present than without one.

Based on the coordination analysis that PGE uses to analyze and identify overloaded protective devices, the sizes of fuses and reclosers may need to be increased, and the devices may need to be relocated to prevent overload and maintain reliability. If recloser changes are warranted, PGE’s practice is to replace a recloser that does not meet its current standards rather than retrofitting the recloser. That is because it would be cost-prohibitive to retrofit existing reclosers to meet PGE distribution design standards requiring voltage sensing equipment on both the line and load sides of the recloser to allow for synchronizing capability.

As an example, hydraulic reclosers on the PGE system typically must be replaced with electronic reclosers due to the following reasons:

- Hydraulic reclosers do not have the voltage sensing, relaying, and communications capabilities required by standards.
- They have lower ampacity ratings than new electronic reclosers.
- They have higher maintenance needs and costs than new electronic reclosers.

If an electronic recloser is required, current transformers (CTs) must be integral to the recloser and have a ratio of 1000:1 or 500:1. Internal voltage sensors must also be provided on the source side of each recloser pole. The voltage sensors must have a magnitude accuracy of 2% or better, and a phase degree accuracy of ±1.5 degrees. Load-side voltage sensors must be provided for sensing voltage on all three phases of the recloser with the same or better accuracy as the source-side internal voltage sensors.

3.6.3.3 Circuit Breakers

If a change to the feeder circuit breaker is required as a result of the studied DER project, PGE may determine that the replacement of the circuit breaker is necessary due to the characteristics of the existing circuit breaker. For example, if new protective relays are required, installing new protective relays in some existing circuit breakers can be more complex and time-intensive than installing a new circuit breaker with relays already installed and pre-wired.

3.6.3.4 Distribution Line Fusing and Coordination

Output from the proposed DER may result in equipment desensitization and coordination. PGE studies these issues as necessary to ensure fault clearing devices are adequately sized to isolate the fault and can do so under acceptable limits.

3.6.4 Substation Requirements

Step-down transformers that reside in substations designated to serve PGE customers are often referred to as distribution power transformers. Although from site to site these transformers vary in size and voltage, a standard installation for PGE is a 16.8/22.4/28 MVA nameplate transformer with 120:13.2 kV stepdown voltages. These transformers have an LTC at the low voltage terminals used to regulate or control voltage to within Range A service voltage limits (114 V to 126 V on a 120 V_{base}) as defined by ANSI C84.1-2016 standard. For distribution power transformers that are sized smaller than 15 MVA, separate voltage regulators are utilized in lieu of the LTC.

Under certain conditions, such as light loading, DERs have the capability of introducing current through substation equipment and onto PGE’s transmission system. This is commonly referred to as backfeed. Backfeed is limited based on when current begins to flow in reverse through the substation transformer. In the event when backfeed is at risk of occurring, PGE substation impacts are explicitly analyzed. The following are six types of substation requirements.

3.6.4.1 Voltage Stability Requirements and Harmonic Distortion Limits

Traditionally, utility facilities were designed for unidirectional power flow. With the addition of DERs, two-way flows on the PGE system are possible at any time. Due to this, DER penetration on distribution feeders may have an adverse system impact on PGE’s electrical distribution or transmission systems.

The addition of DERs requiring inverters may introduce harmonics to the PGE system. These harmonics can potentially distort the voltage and contribute to equipment heating, damage, and loss of life. Also, harmonics can cause protective relay misoperations and, in some circumstances, may affect revenue metering accuracy.

The total harmonic distortion shall not exceed 5% on the PGE system. PGE's harmonic distortion requirements are based on the stricter of the most recent version of IEEE 519-2014, Recommended Practice and Requirements for Harmonic Control in Electric Power Systems, or PGE's internal requirements.

If an applicant is negligent in correcting a harmonic distortion problem that is adversely affecting electrical service to other customers, PGE reserves the right to consider refusing service, discontinuing service, or regulating hours of service to the non-compliant applicant.

3.6.4.2 Hot Line Indication

PGE reviews the relays installed on the feeder associated with the potential DER. If the relays are not capable of hot line indication (and transfer trip, if needed), PGE specifies the need to replace the existing relay per PGE's current standard. If hot line indication/hot line blocking is required, then a sensing potential transformer (PT) is required.

3.6.4.3 Preferred Substation Relaying

PGE exclusively uses Schweitzer Engineering Laboratories (SEL) microprocessor-based protective relays. PGE has standardized the SEL-487E Transformer Protection Relay for transformer protection.

This relay has the functionality for DER interconnection protection (3V0 detection) required by PGE design standards. Other SEL relays are used for feeder protection, including hot line blocking and transfer trip.

3.6.4.4 Conditions Requiring Transfer Trip

PGE requires transfer trip with hot line indication/blocking if the total DER capacity on the bus can exceed 80% of the minimum load of the substation transformer.

Transfer trip is a practice used in the utility industry to prevent unintentional islanding by DERs. Unintentional islanding can compromise the operation of utility equipment such as reclosers and switchgears as well as damaging the applicant's DER and the equipment of other PGE customers connected to the island.

Installing transfer trip will also take the DER offline for reliability events that the DER cannot detect (for example, due to the DER not being inverter-based or the DER having a multi-inverter configuration) and is used to remove the DER from the PGE system when switching or other system work is required.

If PGE determines that transfer trip is required, the applicant must install a relay or ancillary device that uses SEL Mirrored Bits and the SEL Mirrored Bits Transfer Trip protocol (MBTT). The SEL-751 and SEL-351 relays are both capable of MBTT. The applicant must also install a device capable of communicating via SEL Mirrored Bits.

PGE is currently reviewing the safety and reliability impacts and operational requirements of equipment alternatives to transfer trip for new or modified DER. This is an evolving area of the utility industry in part due to changes in inverter standards and testing. Pending the outcomes of PGE's review, PGE may revise its requirements for substation backfeed protection in the future.

If transfer trip is required, 3V0 protection on the high side of the substation transformer may also be required.

3.6.4.5 Overvoltage (3V0) Protection

When there is ground fault on the high side of a tapped substation transformer or a transformer at a line control station, the line relays trip the line breakers leaving the substation primary without a ground reference. The DER capacity beyond 80% of the transformer load creates an overvoltage condition on the unfaulted phases of up to 173% of normal phase-ground voltage. Until the fault is cleared and the DER separated, the arresters on the unfaulted phases are exposed to this overvoltage and continuously conduct, leading to thermal runaway and arrester failure. The overvoltage condition can also damage the transformer and the line insulators. At low DER penetration, the relatively large, stranded load facilitates rapid cessation of the DER. At higher penetration levels, the DER removes itself increasingly slowly.

PGE follows one of two approaches to address this fault-induced overvoltage condition:

- Prevent the overvoltage condition by making the substation transformer appear to the PGE transmission system as an effectively grounded source. This requires replacement of the substation transformer with a different configuration or the installation of a grounding bank.
- Rapidly detect the overvoltage condition and remove the transformer as a source. This is referred to as 3V0 sensing (or 59N protection).

Once the DER is separated from the transmission system for fault-induced overvoltage, it is essential that the DER also be tripped to allow PGE’s transmission system to reenergize PGE’s distribution system without risk of closing in out-of-phase to still-energized portions of PGE’s distribution system.

The equipment required to rapidly detect the fault-induced overvoltage condition, remove the transformer as a source, and trip the DER is:

- Three-phase PT on the high side of the substation transformer
- Circuit switcher or circuit breaker on the high side of the substation transformer
- Dual SEL-487E relays to detect overvoltage and for overall transformer protection
- Transfer trip to the DER via SEL Mirrored Bits

3.6.4.6 Communications

If transfer trip is required, then communications between the applicant’s equipment and a PGE-owned communicating device is needed. PGE’s current standard is to use fiber communication for transfer trip schemes. Fiber deployment is PGE’s standard due to its low level of ongoing maintenance, long cable life, low security risk, resistance to interference, easy accommodation of different technology platforms, and PGE’s experience outside and inside plant fiber networks. PGE has not installed a new power line carrier for telecommunications in many years due to concerns regarding speed, maintenance, and reliability; therefore, power line carrier is not allowed for any interconnections.

A small narrow band radio solution that is smaller and less expensive to deploy than the standard PGE Microwave radios is limited in functionality and bandwidth but may not be able to provide the required level of reliability and latency. Other narrowband radio considerations include limited distance, line of sight, frequency coordination, potential interference, and regular radio infrastructure maintenance. These radios can only be utilized for a single function such as MBTT. These point-to-point solutions need to be evaluated on a site-by-site basis. Additional engineering, towers, and path analysis is also necessary to determine if radios could be used for any transfer trip scheme.

3.6.5 Transmission System Requirements

If there is backfeed onto the transmission system caused by the proposed DER, then a transmission analysis will be performed following NERC standards to ensure there are no adverse impacts to the transmission system.

3.6.6 Ownership of New Facilities and System Upgrades

For secondary-metered DER, PGE will own facilities up to the termination of our cable/conductor. In most cases, this standard also applies primary-metered facilities. For primary-metered facilities the change of ownership must occur within 100 feet of the POI and is subject to PGE approval.

Due to the highly specialized and critical nature of communications equipment, when communications infrastructure is required, PGE will own all necessary communication equipment up to the fiber termination panel at the applicant site. This is to ensure safety, reliability, and security of both the applicant's DER and the PGE system.

As noted in Section 1.1, Overview of System Conformity, Limitations, and Upgrade Cost Requirements, the applicant is solely responsible for the cost of PGE designing and constructing any new facilities and system upgrades required to safely and reliably accommodate the proposed DER, as well as the cost of maintaining and repairing the new facilities and system upgrades.

4 Interconnection Agreement

An interconnection agreement must be signed by PGE and the applicant for every DER prior to the operation of the DER on the PGE system. Additionally, any payment schedules in the interconnection agreement must be met by the applicant before PGE initiates its design, procurement, and construction activities to accommodate the DER. An example of the standard form of the net metering, small generation, and community solar interconnection agreements is available on PGE's website.

- For DERs requiring studies, the interconnection agreement is presented to the applicant after the final study of the DER is complete. The agreement will contain the estimated interconnection cost and schedule based on the last study. Execution of the interconnection agreement and payment of a specified portion of the estimated costs must be made before PGE begins its design, procurement, and construction activities. All upgrade costs must be paid before the DER can be energized on the PGE system.
- For DERs not requiring studies (for example, that qualify for and pass tier technical screenings not requiring studies), the applicant may be able to sign a standard utility interconnection agreement at the time of its application or thereafter. PGE will include minor equipment modification costs in the agreement where appropriate and provisions for payment of those costs before the DER is energized.

Overall, interconnection agreements often contain elements such as responsibilities and requirements for operation; maintenance; monitoring; metering; testing; inspection; access; recordkeeping; disconnection and restoration of interconnection service; cost responsibilities and billing; insurance requirements; descriptions of required facilities and system upgrades to accommodate the DER; estimated applicant interconnection costs; estimated schedule covering design, procurement, and construction of those facilities and upgrades; and various other legal terms and conditions. PGE requirements for some of those contract elements are highlighted in subsequent sections of this document.

A small generator applicant connecting a DER as a QF will also sign a PPA with PGE. Such an applicant must also abide by interconnection-related requirements in the PPA. A CSP applicant will also sign a Community Solar Program Purchase Agreement and must abide by any interconnection-related requirements therein.

5 Design, Procurement, and Construction

Depending on the technical screening and study results as reflected in the applicant's interconnection agreement, a DER interconnection may require construction at the PGE distribution system, substation level, and transmission system. The major utility activities that precede construction of new interconnection facilities and system upgrades are completion of design and procurement of required materials.

The applicant bears the costs pertaining to distribution facilities, substation facilities, transmission facilities, communication facilities, and system upgrades related to its new or modified DER. As PGE experiences higher volumes of DER penetration at individual feeders and substations, the cost, complexity, and timeline for interconnecting DERs can increase at those system locations, and adverse substation and transmission impacts are likely to occur more frequently than in the past.

While PGE endeavors to complete its design, procurement, and construction activities efficiently and place the new or modified DER in-service according to the schedule in the interconnection agreement, the schedule is not guaranteed because there are many factors, including those outside of the utility's control that can affect the schedule. These factors include the interconnection progress of DERs ahead in queue, construction resource availability, equipment and material availability as well as delivery, extreme weather events or other causes of outages and construction delays, AHJ delays in approvals, seasonal system reliability impacts (for example, if a delay causes construction to be pushed into a time of year that PGE cannot perform a construction task), and applicant delays in responding to information requests. Additionally, if milestone payments or other required deliverables (such as schedules, engineering designs, equipment information, etc.) are not received before or during the cure period for a given milestone, PGE reserves the right to discontinue work on the project until such time as payments or other deliverable, as identified in the interconnection agreement, have been received by PGE.

6 Commissioning, Inspecting, and Witness Testing

PGE does not commission an applicant's DER. The applicant is required to provide paperwork indicating all required inspections by non-utility parties have been completed and all required permits have been obtained. PGE may require its presence for commissioning tests.

6.1 Commissioning Technical Tests

The applicant is responsible for commissioning the DER in compliance with the IEEE 1547-2018 technical requirements and employing equipment that has been tested according to UL 1741 SB standards. Per IEEE 1547-2018, the applicant's commissioning process shall include tests of DER response to abnormal voltage and frequency, synchronization, interconnect integrity, unintentional islanding, limitation of DC injection, and harmonics. Regarding commissioning, PGE reserves the right to require the applicant follow standards as appropriate to protect the safety and reliability of the PGE system, consistent with good utility practice.

6.1.1 Additional Requirements for Transfer Trip Protection Testing

If transfer trip is required, PGE will perform end-to-end testing prior to interconnection of the DER. The applicant must provide relay settings (or drawings if using an auxiliary device; for example, SEL-2505) before testing can occur. A PGE relay/meter technician will witness the tripping and relay operation at the applicant's DER site during the testing.

6.2 Authority Having Jurisdiction Inspections and Permits

Before the applicant's DER can be commissioned, it must meet all relevant requirements of government AHJs. This includes passing all relevant inspections and obtaining all relevant permits including those related to construction, electrical, and safety codes.

6.3 Metering Commissioning

Each new DER interconnection requires testing and verification by PGE of the applicant's revenue grade metering prior to granting a certificate of completion. PGE will coordinate with the applicant to schedule a date for commissioning and witness testing as PGE requires the applicant be present during the metering commissioning.

For inverter-based DERs, PGE will verify inverters are capable of generating, the PGE-installed meter is functional, and any additional PGE equipment is working properly during testing. For testing of machine-based DER, PGE will verify proper operation of PGE-installed metering and any other equipment. The metering tests are conducted and recorded per PGE's testing and maintenance standards.

6.4 Witness Testing

In addition to metering commissioning, PGE conducts, as appropriate, onsite witness tests (for example, visual verification) of DERs before new or modified DERs are energized to check the DER complies with all relevant interconnection safety and reliability requirements. For applicant interconnection equipment that does not meet the definition of lab-tested equipment, the witness test may, at PGE's discretion, also include a system design and production evaluation according to IEEE 1547-2018.

The overall scope of the witness test may include but not be limited to communications verification, points list verification, verification of normal operations, and verification of critical functions (for example, loss of communication circuits, transfer trip, transfer trip disabled, breaker operations). Additionally, the PGE team performing the witness test reserves the right to check nameplate capacities on the facility's inverters.

A witness test checklist applicable to small generator DERs, including a list of documents that must be provided by the applicant, is provided in Section 15, PGE Small Generator Witness Testing Checklist.

7 Operation and Maintenance of Customer Facilities

The interconnection standards of PGE do not end when the DER is energized. They must be adhered to for the full duration of the interconnection agreement, regardless of whether the DER ceases producing electricity. For a small generator that is a QF, there may be additional operational requirements in an applicant's power purchase agreement (PPA) with PGE. Some key operations and maintenance requirements are summarized in the following sections.

7.1 Overall Operation and Maintenance Standards

Per OAR 860-082 (small generator and community solar) and OAR 860-039 (net metering), the applicant must operate and maintain the DER and associated interconnection equipment in compliance, at all times, with applicable federal, state, and local government laws and regulations, IEEE standards, good utility practice, the interconnection agreement, and, as applicable, the PPA with PGE.

Changes to DER operating or maintenance practices that conflict with federal, state, or local government laws and regulations, IEEE standards, good utility practice, the interconnection agreement, or the PPA are not allowed without PGE review and approval. Any changes other than minor equipment modifications as defined by OAR 860-082 (small generator and community solar) or OAR 860-039 (net metering) made by the applicant without prior PGE approval may cause PGE to temporarily disconnect the DER from the PGE system. Certain modifications may necessitate a new interconnection application.

7.2 General Safety Requirements

The DER is required to cease to energize when there is a fault on the feeder to which it is connected and shall not energize the feeder when the feeder is de-energized. This also limits the applicant's DER from receiving electricity from an alternate source during a loss of service unless otherwise and explicitly stated in the interconnection agreement.

7.3 Islanding

The applicant's DER must isolate itself from the PGE system in the event of a loss of service from PGE's source. The applicant's DER must also ensure it is incapable of re-energizing the PGE system after a loss of service, creating an unintentional island. Per IEEE 1547-2018, for an unintentional island in which the DER energizes a portion of the PGE system, the DER shall locate the island and cease to energize the PGE system within two seconds of the formation of an island. Following an event, the islanded applicant may reconnect to PGE via closed transition with prior consent from PGE. The role of and rationale for transfer trips in preventing unintentional islanding under specific circumstances is described in Section 3.6.4.4, Conditions Requiring Transfer Trip. Communication requirements to support transfer trip are described in Section 3.6.4.6, Communications.

When a DER is designed to island intentionally during a system outage, for example a storage system installed behind the meter to provide resiliency at a customer site, the DER must include a transfer switch, power control system, or other device that functions like a transfer switch, isolating the islanded DER and critical load from the distribution system. When a DER utilizes a power control system, that system must be tested by a NRTL testing facility to meet the UL1741-Power Control System Certification Requirement Decision until similar test procedures for power control systems are included in a standard.

When evaluating a DER that intentionally islands, PGE will need to review the methods and the operation of the transfer switch or control device. To conduct that review, additional information will be required from the applicant at the time of submission.

The following documentation shall be submitted as an attachment with the interconnection application:

- Manufacturer and model of the transfer switch, device or power control system, or the components that make up the system
- The technical specifications of the transfer switch, device, or power control systems
- A description of the operating modes, services, and any specific settings that are enabled, and how the hardware/software present in the design is used to accomplish the goals of the mode being used
- A description of how the operating modes and services not being enabled are locked down to prevent unintentional enabling
- Additional information that may be requested by the utility to clarify the operation of the device or power control system

7.4 Temporary Disconnection

PGE or the applicant may temporarily disconnect the DER as long as necessary. PGE and the applicant must cooperate to restore normal operations for the DER as soon as practical following a temporary disconnection.

Events causing temporary disconnection include those listed immediately below. These events apply equally to all applicants except the forced-outage requirement, which pertains only to small generator and CSP applicants.

- **Emergency Conditions**—In emergencies, PGE or the applicant may immediately disconnect the DER with no prior notice. The party disconnecting the service must notify the other party promptly and provide available information on the causes and expected impacts, duration, and corrective actions needed.
- **Routine Maintenance**—PGE or the applicant must make an effort to provide notice to the other party of at least 5 business days before it conducts maintenance, repair, or construction on the DER or PGE system that requires disconnection.
- **Forced Outage**—When the utility makes repairs to the PGE system requiring a forced outage, PGE will use reasonable efforts to provide notice to the applicant prior to the disconnection. If prior notice is not given, PGE will document the circumstances of the disconnection.
- **Disruption or Deterioration of Service**—If PGE determines that continued operation of the applicant's DER will likely cause either disruption or deterioration of utility service to other PGE customers, or damage to the PGE system, PGE may disconnect the DER and provide relevant documentation of its decision to the applicant upon request. In emergencies, no prior notice is

required for such disconnections. In non-emergencies, PGE allows the small generator or CSP applicant 5 business days to remedy the DER's condition before disconnection.

- **DER Changes other than Minor Equipment Modifications**—If such modifications are made by the applicant prior to the changes being approved in writing by PGE, the utility may disconnect service.

In addition to the temporary disconnection provisions noted above, PGE may require an annual test in which a net metering, CSP, or an inverter-based small generator DER is disconnected from the PGE system to ensure that the DER's inverter stops delivering power to the utility grid.

7.5 Labeling

All DER systems are required to follow the labeling requirements as outlined by the National Electrical Code (NEC), National Electrical Safety Code (NESC), Occupational Safety and Health Administration (OSHA), the AHJ(s), the State of Oregon, and their agreements with PGE. Labeling should be made of an engraved metal or plastic. It must be permanently affixed to the meter base, ac disconnect (when one is required), or switchgear.

If the ac disconnect is more than 10 feet from the meter, then a permanent placard must be posted at the meter indicating the location of the switch. The labeling must be approved by PGE prior to posting.

PGE will install labeling on customer switchgear indicating the location of the PTs and CTs to aid with switching during emergencies. For more information on labeling, see PGE's ESR 2024 section 3.9.8.

7.6 Special Access Issues for Isolation Devices

The applicant may request approval from PGE to provide access to an isolation device that is contained in a building or area that may be unoccupied, locked, or otherwise not readily accessible to outside parties. If a request to PGE is made and approved, the applicant must provide a lockbox capable of accepting a lock provided by PGE that provides ready access to the isolation device. The applicant must install the lockbox in a location that is readily accessible by PGE and must affix a placard in a location acceptable to PGE that provides clear instructions on how to access the isolation device. PGE must review and approve the placard design and language prior to its placement.

7.7 Frequency Stability

PGE is responsible for maintaining system frequency at 60 Hertz (Hz) across its service territory per standard system requirements across the United States electric grid. PGE requires that all DER operate in sync with PGE's 60 Hz system frequency. Unless otherwise noted as part of a frequency response program, PGE requires that the DERs be able to immediately disconnect itself from the PGE system and cease operations once its output frequency strays from the allowable limits set by IEEE 1547-2018, Clause 6. DERs must also be capable of high and low frequency ride through according to the same standard. Furthermore, DER must be capable of operating in droop control according to the requirements of that standard. PGE will coordinate with the applicant on specific design requirements to support frequency response program participation as needed.

7.8 Record-Keeping and Retention

When a DER undergoes maintenance or testing in compliance with the OAR 860-082 (small generator and community solar) or OAR 860-039 (net metering), the applicant must retain written records documenting the maintenance and the results of testing for at least seven years. The applicant must provide copies of these records to PGE upon request.

7.9 Special Issues Related to Energy Storage

Energy storage (ES DER), having unique capabilities as both a source and a load must only be operated in modes consistent with the project's interconnection application materials submitted to PGE, approved by PGE, and the interconnection agreement. If an energy storage DER is expected to change its operating modes outside those that PGE approved; PGE must be contacted to determine if further review is required.

8 Customer Equipment Requirements

Small generator applicants must meet all requirements in OAR 860-082 (small generator). Net Metering applicants must meet all requirements in OAR 860-039 (net metering). CSP applicants must meet all requirements in OAR 860-088 (CSP). DER and related customer equipment must also meet standards as designated by PGE and local electrical and building codes. Descriptions of certain equipment requirements are summarized below.

8.1 Inverters

Inverters must be UL 1741 SB-tested and compliant. Non-UL 1741 SB inverters will not be considered. Any material modifications to the inverter's standard settings must be noted with the interconnection application materials. These may include, but are not limited to, static or dynamic power factor adjustments, use of smart inverter functionality, and permanent curtailment of the maximum inverter output compared to its ac nameplate rating provided by the inverter manufacturer.

8.2 Supervisory Control and Data Acquisition

PGE offers direction to applicants on supervisory control and data acquisition (SCADA) requirements for their DER on an individual project basis. An example SCADA schematic is provided in Figure 2. That schematic represents a general cable and conduit design. Applicants' individual site requirements may alter the design, and applicants must coordinate with PGE on any changes to the design.

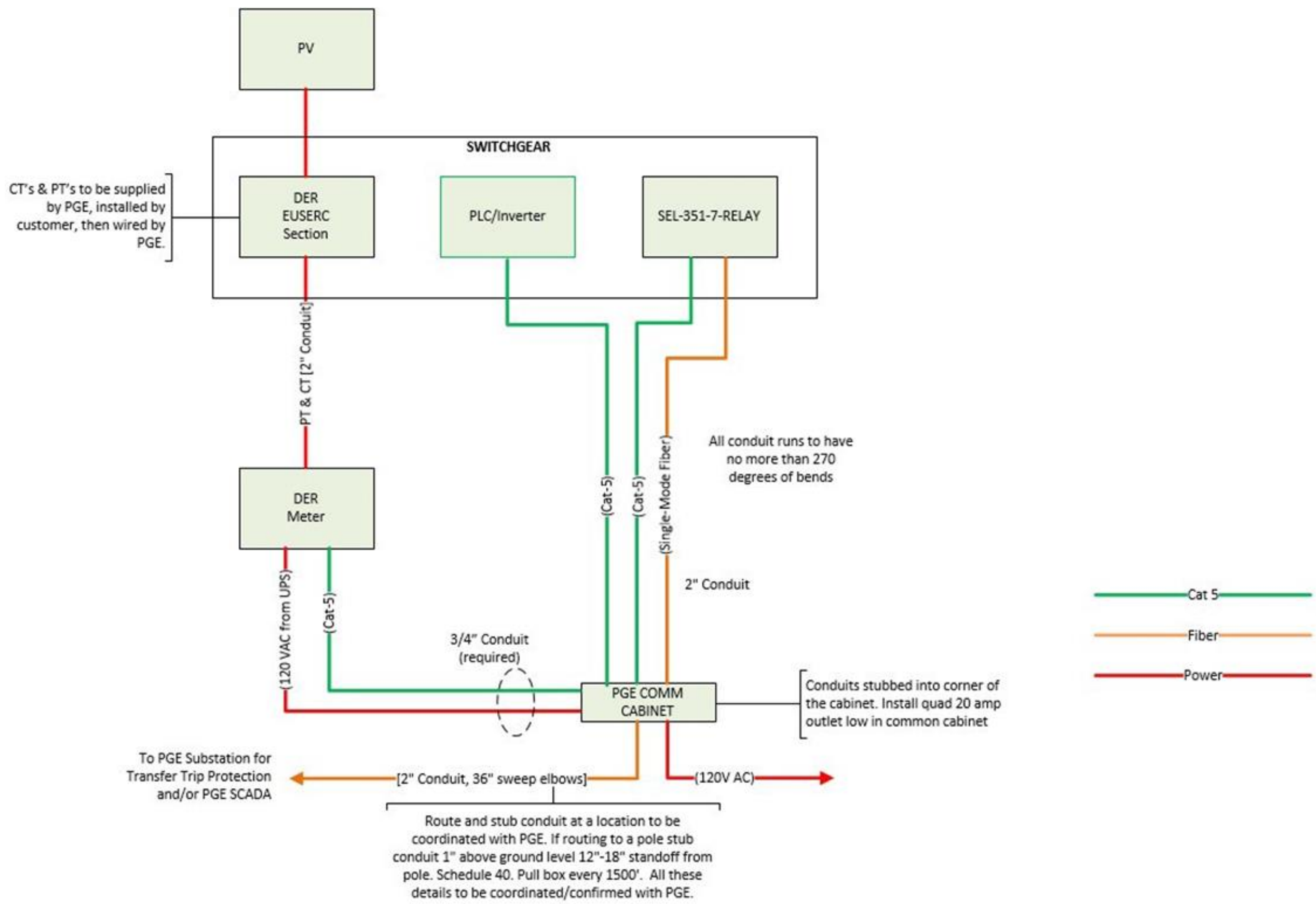

Figure 2. Example Schematic of SCADA Cable and Conduit Requirements for DER

Metering requirements as they relate to SCADA are described in Section 9, Metering Requirements.

8.3 Effective Grounding

Grounding and bonding are critical for safety and electrical reliability. The applicant is responsible for ensuring the DER's electrical wiring and service equipment is grounded and bonded in accordance with applicable National Electrical Code requirements.

The DER must also provide the same level of effective grounding as the PGE system to avoid an adverse impact on the PGE system. Maintaining effective grounding is critical to protecting equipment of PGE and its customers. PGE system grounding is designed to provide a path of least resistance for potentially damaging electrical current following a surge or fault on the PGE system.

As noted in Section 3.6.4.5, Overvoltage (3V0) Protection, faults on the PGE system may create an overvoltage condition as high as 173% of the nominal voltage in the absence of effective grounding. Requiring effective grounding ensures potentially damaging, temporary overvoltages remain in the tolerable limits of 125–138% of nominal voltage. More information on acceptable transformer configurations and grounding requirements can be found in Section 3.6.4.5, Overvoltage (3V0) Protection.

8.4 Electric Service Requirements

For low-voltage services, services less than 600 V, PGE's Electric Service Requirements (ESR) book is to be followed in full. For medium voltage services, services 600 V to 34.5 kV, PGE's Medium Voltage Requirements book is to be followed in full. The latest versions are available on PGE's website. Within the Medium Voltage Requirements book, guidance on customer-owned transformers beyond the point of delivery must be followed, if applicable. See Figure 3.

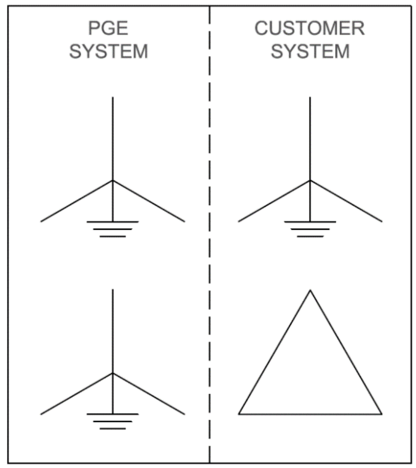

Figure 3. Interconnection Configurations Acceptable (STD-D-6901)

8.5 Disconnecting Devices

For secondary voltage connections of parallel operations, a lockable AC disconnect switch is required (with very limited exceptions per OAR 860-082-0030(4)(b)). This switch must be within 10 feet of the interconnection meter unless another location has been approved by PGE.

For primary voltage connections, lockable switching equipment (disconnect switch, breaker, or recloser) with a visible break to isolate the DER from the PGE system is required.

8.5.1 Plot Plan

If an ac disconnect switch or switching equipment is required, then a single-line diagram and site plan must be included in the interconnection application. The single-line diagram must show the complete circuit between the DER and the proposed POI or PCC, including all protective devices and transformers. The site plan must show the DER location and the accessibility of the disconnect switch. Examples can be found in Section 12, Example Single-Line Diagrams.

8.6 Protection Devices (Relays)

The applicant is responsible for the protection of its DER. For primary voltage interconnections, the applicant is required to have a relay with current and voltage protection on the primary side of the transformer to isolate PGE from a disturbance on the DER. For proposed three-phase DER interconnections, overvoltage and undervoltage relaying must be included on each phase, and overfrequency and underfrequency must be included on at least one phase. Three-phase systems must also be gang operated if any single phase of the protection devices detect a power quality violation. More information on the exact relay types and settings that comply with PGE protection standards can be found in Section 8.6.1, Relay Types and Settings. PGE review of settings may be required prior to energization.

As explained in Section 3.6.4.4, Conditions Requiring Transfer Trip, if PGE determines that transfer trip is required, the applicant must install a relay or ancillary device that uses SEL Mirrored Bits. Under this configuration, the applicant is expected to need an SEL transceiver and fiber optic jumper to connect to PGE's patch panel.

8.6.1 Relay Types and Settings

The settings required by PGE for each relay type typically correspond to the settings as defined in IEEE 1547-2018. Brief descriptions of the purpose of each relay type are provided for reference in Table 5. All relay types may not be applicable to a particular DER.

Table 5. Descriptions of Relays

Related Type	Purpose
Undervoltage with time delay	Detect undervoltage conditions as a result of unintentional islands or other abnormal operations
Overvoltage with time delay	Detect overvoltage conditions as a result of unintentional islands or other abnormal operations
Overfrequency with time delay	Detect overfrequency conditions as a result of unintentional islands or other abnormal operations
Underfrequency with time delay	Detect underfrequency conditions as a result of unintentional islands or other abnormal operations
Distance Relaying	Detect faults on the transmission system and isolate the DER to remove any additional generation to the fault contribution
Negative Sequence Overcurrent / Overvoltage	Detect upstream protection device operations to improve fault sensitivity
Synchronism Check	Ensure synchronous operations of the DER

8.7 Ancillary Devices

If the applicant is installing relays incapable of sending/receiving Mirrored Bits, then an ancillary device can be used to translate Mirrored Bits to the relay. This device will have hard-wired inputs and outputs as well as a fiber connection for the Mirrored Bits. Typical devices are the SEL-2505 and SEL-2506. Check with PGE on fiber type needed. Standard PGE fiber is 144-count all-dielectric self-supporting (ADSS) fiber cable.

8.8 Paralleling Devices

When a DER is generating for a duration of 100 milliseconds (ms) or more while connected to the PGE system, the DER is considered to be in parallel operation. Per IEEE 1547-2018, the paralleling device shall be capable of withstanding 220% of the interconnection system rated voltage.

8.8.1 Secondary Service

PGE provides the following secondary voltages (underground/overhead):

- Single-phase, 120/240 V, three-wire, grounded
- Single-phase, 240/480 V, three-wire, grounded
- Three-phase, 208Y/120 V, four-wire, grounded, wye
- Three-phase, 480Y/277 V, four-wire, grounded, wye

8.8.2 Medium Voltage Service

PGE's medium voltage system has a nominal operating voltage of 12.47 kV, with a maximum root-mean-square (RMS) design voltage of 15.5 kV. High-voltage instrument transformers and transformer-rated meters are required for applicants taking service at medium voltage. PGE's Medium Voltage Requirements are to be followed in full. The latest version of the Medium Voltage Requirements book is available on PGE's website.

PGE will provide medium voltage delivery to qualified applicants directly, without transformation, from the medium voltage electrical distribution facilities (standard for the location in which service is requested) if the following conditions apply:

- The service at medium voltage will not, in the judgment of PGE, adversely affect the operation of the PGE system or service to other customers.
- The service supplied is distributed in a safe and reliable manner.
- The applicant provides switching devices with appropriate overcurrent protection to isolate the PGE system from disturbance on the applicant-owned primary facility.
- The applicant is responsible for the operation and maintenance of all applicant-owned equipment. PGE does not provide replacement parts for applicant-owned equipment. PGE will not energize applicant-owned facilities beyond the point of delivery.

As stated in Section 3.6.4.6, Communications and Section 8.6, Protection Devices (Relays), the applicant is responsible for all communications equipment (for example, fiber jumpers, transceivers) behind the terminating fiber optic patch panel at the applicant site. This is typical for sites requiring transfer trip. However, this demarcation point may be further downstream for sites without direct transfer trip.

9 Metering Requirements

The applicant is responsible for all costs associated with the metering and data acquisition equipment as outlined in this section. PGE and the applicant must have unrestricted access 24 hours a day, 7 days a week, to metering and data acquisition equipment to conduct routine business or respond to an emergency. This section summarizes PGE's interconnection service voltages and associated metering equipment.

9.1 Secondary Service (up to 600 V)

PGE's ESR provides interconnection and equipment requirements for relocated, rewired, and new services. For Meter Socket Requirements, refer to Section 3.9, Table 5, of the ESR and confer with the appropriate section of the ESR. Meter clearance requirements are provided in Section 5 of the ESR.

For single-phase services over 320 A or three-phase services over 200 A, the applicant must submit a drawing package for PGE review. The package must contain a site plan, electrical one-line, electrical room layout (if applicable), working clearances, and manufacturer drawings with EUSERC references. The applicant must receive confirmation that equipment meets PGE requirements from PGE Meter Operations prior to installation.

9.2 Medium Voltage Service (greater than 600 V)

PGE's Medium Voltage requirements are available in the Medium Voltage Requirements. The applicant must consult with PGE, apply for service, and obtain an approved job sketch before construction. The switchboards must meet EUSERC Section 400 requirements for service voltages of 12.47 kV. The metering equipment must be located within 100 feet of the POI. Consult PGE for equipment requirements for service voltage of 34.5 kV.

The applicant must submit drawings of metering equipment to PGE for review. Information required in the drawing package is provided in PGE's Medium Voltage Example Drawing Package. Drawings must include the company name, job address, contact address, and phone number of the manufacturer's representative. The applicant must receive the Medium Voltage Service Review Complete letter that includes engineering technical review feedback before ordering equipment.

The applicant must install a load-side point of isolation in the switchboard down-stream of PGE metering equipment. The load-side point of isolation separates the applicant's DER from the PGE system and provides a visible open for establishing a clearance point for PGE personnel to work on PGE cable and equipment upstream of the applicant's equipment. The load-side point of isolation must be a blade-and-jaw type. The load-side point of isolation equipment is in addition to any downstream protective device, disconnecting means, or switching equipment provided by the applicant. Applicant equipment is not allowed upstream of the load-side point of isolation.

NOTE: In some cases, PGE may require a line-side point of isolation in addition to the load-side point of isolation.

IMPORTANT: Applicants are responsible for operating (opening and closing) their load-side point of isolation for PGE personnel when requested, for planned or unplanned outages, 24 hours a day, 7 days a week, 365 days a year. PGE personnel are not allowed to operate equipment owned by applicant.

The load-side point of isolation should not be used to pick up customer load. PGE expects applicants to use an applicant-controlled protective device, such as a breaker or resettable fault interrupter, to pick up load after a load-side point of isolation is closed and PGE energizes the medium-voltage service.

9.2.1 Switchboard Enclosure Customer Requirements

The applicant must provide and install:

- For 12.47 kV: All hardware required to comply with EUSERC Section 400.
- For 34.5 kV: All applicable hardware required to comply with EUSERC Section 400 and PGE requirements.
- Phenolic labeling as required by EUSERC 400 and PGE requirements.
- Load-side point of isolation to serve as visible open for PGE lock-out/tag-out procedures.
- Clear and level workspace that is 78-inches high and 60-inches deep around the metering equipment, measured from equipment exterior
- Minimum 120 inches (10 feet) of clear, hard, and level workspace in front of termination compartment
- Concrete mounting vault with a concrete pad at least 4-inches thick for the switchboard metering equipment
- Installing instrument (current and potential) transformers provided by PGE for metering
- Refer to Medium Voltage Requirements for comprehensive service requirements

9.2.2 Switchboard Enclosure PGE Requirements

PGE will provide and install:

- Meter(s)
- Meter test switch(es)
- Meter secondary wiring
- Providing current transformers (CTs) and potential transformers (PTs) for PGE metering
- Refer to Medium Voltage Requirements for comprehensive service requirements

The line-side point of isolation is required and will be addressed in PGE's design. In some circumstances, it may be beneficial to install a line-side point of isolation in applicant's equipment.

9.2.3 Meter Enclosure Requirements

PGE's standard for medium-voltage services is to meter customer with a remote meter enclosure. The applicant-owned remote meter enclosure must be attached to the exterior of the enclosure or placed within 50 feet of the switchboard. The applicant must provide a 5-foot by 5-foot space for the remote meter enclosure.

If remote meter enclosure is mounted to the switchboard, PGE requires:

- Minimum 1-inch duct or PVC conduit from the current transformer compartment to the remote meter enclosure for secondary wiring.
- Minimum 1-inch duct or PVC conduit from the potential transformer compartment to the remote meter enclosure for secondary wiring.

If remote meter enclosure is post-mounted within 50 feet of the switchboard, PGE requires:

- Minimum 2-inch PVC from the switchboard to the remote meter enclosure for secondary wiring from the current transformer and potential transformer compartments.
- Refer to Medium Voltage Requirements for comprehensive service requirements.

9.3 Instrumentation

The applicant must consult PGE for specifications on instrument transformers, the meter test switch, and secondary wiring of instrument transformers prior to ordering the meter enclosure. Enclosure drawings with a site plan and electrical room detail must be provided to PGE for approval prior to installation.

PGE will specify and purchase all revenue metering instrument transformers (CTs and PTs). PGE will provide the instrument transformers to the applicant for applicable switchboard and primary services for the applicant to install. PGE will install the test switch and all secondary meter wiring. All instrument transformers must meet IEEE C57.13-2016 revenue metering requirements and will only be used for PGE revenue metering devices.

9.4 End-Use Customer Switchboard Requirements

All commercial, industrial, and large residential electricity customers of PGE must coordinate their service requirements with PGE. They must provide factory-produced submittal drawings of metering equipment before purchase and installation. Single residential services over 320-amp continuous and all three-phase residential services are considered large residential services.

For commercial, industrial, and large residential service entrance ratings of 800 amps or lower:

- Single-phase services over 320 amps continuous, and three-phase services over 200 amps, require CT metering except as referenced in Section 10.3 of the ESR.
- Refer to Section 10 of the ESR for comprehensive service requirements.

For commercial, industrial, and large residential service entrance ratings of 801 amps or greater:

- An EUSERC-approved switchboard metering section is required.
- The switchboard metering section may be used for three-phase services over 200 amps and single-phase service over 320 amps.
- The metering will be located in the CT section of the cabinet/compartment. The exact location and cabinet requirements are determined by PGE during the metering review.

The meter and test switch may be mounted on the cover of the hinged compartment or located remotely.

- The area below the barrier in this compartment may be used as a main switch (or breaker) compartment, a load distribution compartment, or a bottom-fed terminating pull section.
- The metering compartment shall be on the supply side of the main switch.
- The mounting pad for all switchboard metering enclosures will be a minimum 4-inch-thick revealed concrete pad.
- Refer to Section 11 of the ESR for comprehensive service requirements.

9.5 Metering Considerations with Energy Storage

Similar to other DER, appropriate revenue grade metering shall be installed and owned by PGE. Additional behind-the-meter telemetry may be required at the discretion of PGE to distinguish between net and gross electricity consumption at the customer premises for PGE operational or planning purposes.

9.6 Telemetry

Consistent with OAR 860-082 (small generator) and IEEE 1547-2018, PGE requires monitoring of connection status, real power output, reactive power output, and voltage at the point of connection for interconnections of small generator and CSP DERs with capacity of 3 MW and larger.

More specifically, the following are the minimum required data points to be provided to PGE by way of an ethernet connection to PGE's communications rack installed at the DER location. These points are in addition to any data communications that may be required if the DER location requires transfer trip protection:

- Net real power flowing out or into the small generator facility (analog)
- Net reactive power flowing out or into the small generator facility (analog)
- Bus bar voltage at the POI (analog)
- Communications heartbeat (used to validate the communications path functionality). The logic for the heartbeat is based on both ends of the communications path incrementing the value received and sending the new value out. When the value received reaches a prescribed value, the value is reset. Applicants must coordinate with PGE to ensure compatible logic is used, which requires sending and receiving analog values.
- Online or offline prime mover status (digital). The applicant must coordinate with PGE in the event of multiple prime movers (for example, generation or energy storage technologies).

If an applicant operates equipment associated with a high-voltage switchyard interconnecting the DER to the PGE system and is required to provide monitoring and telemetry, then the applicant must provide the following data to PGE in addition to the data above:

- Switchyard line and transformer MW and MVA values
- Switchyard bus voltage
- Switching device status

The communication must take place via a private network link using a device and protocol deemed suitable by PGE (for example, a remote terminal unit provided by a Distributed Network Protocol (DNP) 3 Level 2 compliant outstation). The DNP3 device profile from the outstation vendor must also be provided to PGE.

PGE requires the following from the DNP3 device:

- Specified DNP3 object types and variations for statuses and analogs
- Statuses included in Polling Class 0 (static value or current state) and Polling Class 1 (static events)
- Outstation capable of responding to interval event polling and interval integrity polling

9.7 SCADA Metering

For SCADA-connected DER, the metering will be consistent with the schematic in Figure 4. The schematic represents a general wall-mounted, remote meter base design. An applicant's individual site requirements may alter the design, and the applicant must coordinate with PGE on any changes to the design.

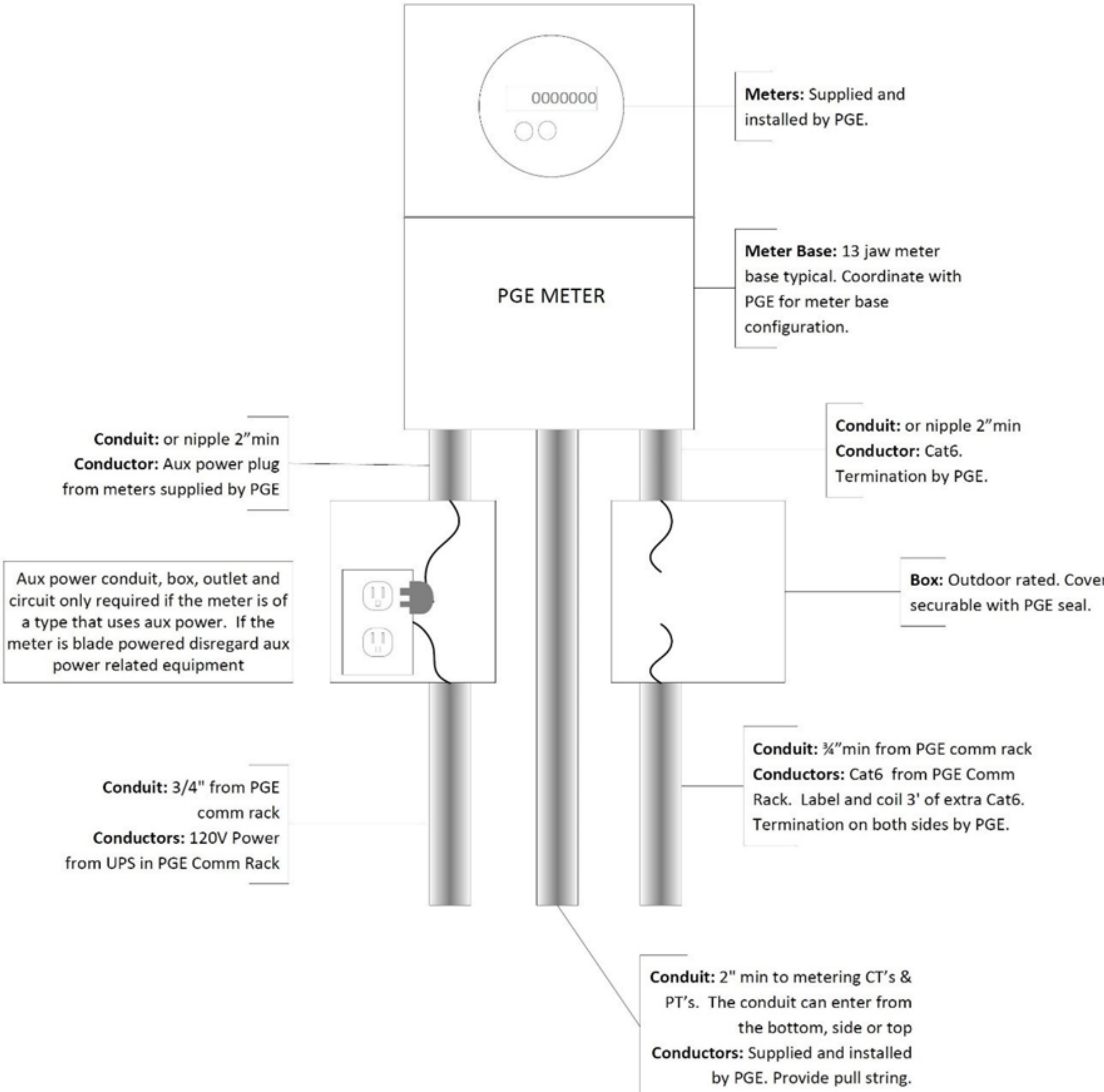

Figure 4. SCADA Remote Meter Base Configuration for DER

10 Additional Technical Requirements for Parallel Operations on Secondary Networks

By definition, when a DER is serving as a source of electric power for greater than 100 ms while connected to the PGE system, the DER is in parallel operations. Interconnection to a secondary network system for parallel operations is limited due to PGE system risks related to cycling network protectors and potential islanding of customers. Although common rules exist for the general network system, there are additional interconnection rules when addressing grid or spot networks.

10.1 Secondary Grid Network Interconnection

For interconnection to a secondary grid network (also called an area network), PGE can accommodate new or modified DER up to an aggregate DER capacity not exceeding the lesser of 5% of the associated network system's peak load or 50 kilowatts (kW). If any of these thresholds are met, no additional DER can be added to the network system. DER interconnecting to a secondary grid network must be configured to not export energy. The system will be reviewed to ensure that the design will protect against export.

There are no additional provisions for connecting to secondary grid networks.

10.2 Spot Network Interconnection

For interconnection to a spot network, PGE can accommodate new or modified DER if aggregate DER nameplate rating does not exceed 20% of the spot network's anticipated relevant minimum load Relevant minimum load of the network will be calculated consistent with the OAR 860-082-0050(2)(c). If this threshold has been met, no additional DER will be approved without additional study that may require significant system upgrades and or protection devices. Additional rules, per IEEE 1547-2018, are as follows:

- Network protectors shall not be used to separate, switch, perform breaker failure backup, or isolate a network or network primary feeder to which the DER is connected from the remainder of the spot network.
- The DER shall not cause operation or prevent reclosing of any network protectors on the spot network. This coordination shall be accomplished without requiring any changes to the prevailing network protector clearing time practice at PGE.
- Connection of the DER to the spot network is only allowed if the network bus is already energized by more than 50% of the installed network protectors.
- The DER output shall not cause any cycling of network protectors.
- The network equipment loading and fault interrupting capacity shall not be exceeded with the addition or modification of the DER.
- DER installations on a spot network, using an automatic transfer scheme in which load is transferred between the DER and PGE in a momentary make-before-break (closed transition) operation, shall meet the above requirements regardless of the duration of paralleling.

11 As-Built Documentation and Interconnection Checklist

Complete the following Table 6 through Table 9, inclusive, and submit to PGE via e-mail to Small.PowerProduction@pgn.com at least two weeks prior to energizing of the facility. Enter as much information as possible and include copies of documents referenced in Table 9 unless previously delivered.

Table 6. DER Facility Information

Interconnection Queue Number	
Facility Name	
Facility Location	
Type of Facility	
Total AC Nameplate Rating	
Interconnection Voltage (kV)	

Table 7. Nameplate Information

Inverter Manufacturer	
Inverter Model	
Inverter Nameplate Rating	
Number of Inverters	

Table 8. Setup Transformer Information

Transformer Manufacturer			
Single-Phase or Three-Phase			
Transformer Rated Capacity (MVA)			
Percent Impedance on Transformer Base			
Low Side Voltage	Delta	Wye	Taps
High Side Voltage	Delta	Wye	Taps

Table 9. Documentation Checklist

Documents Required	Delivery Date
As-Built One-Line	
As-Built Site Plan	
Inverter Specification Sheet	
Step Up Transformer Specification Sheet	
Transfer Trip Relay Settings	
Operation and Maintenance Contact Information	

11.1 Site Requirements

Requirements	Status
PGE Horseshoe Lock in place	☐
Emergency Contact Information posted on gate	☐
AC Disconnect installed	☐
AC Disconnect properly labeled	☐

12 Example Single-Line Diagrams

Figure 5 is an example of a single-line diagram for an inverter-based net metering project.

Figure 6 is a single-line diagram example for an inverter-based small generator. The single line for CSP projects is the same as a small generator.

These figures are provided only for illustrative purposes. Applicants must develop single-line diagrams for their applications, as needed, that are consistent with their project specifics and with all PGE technical requirements.

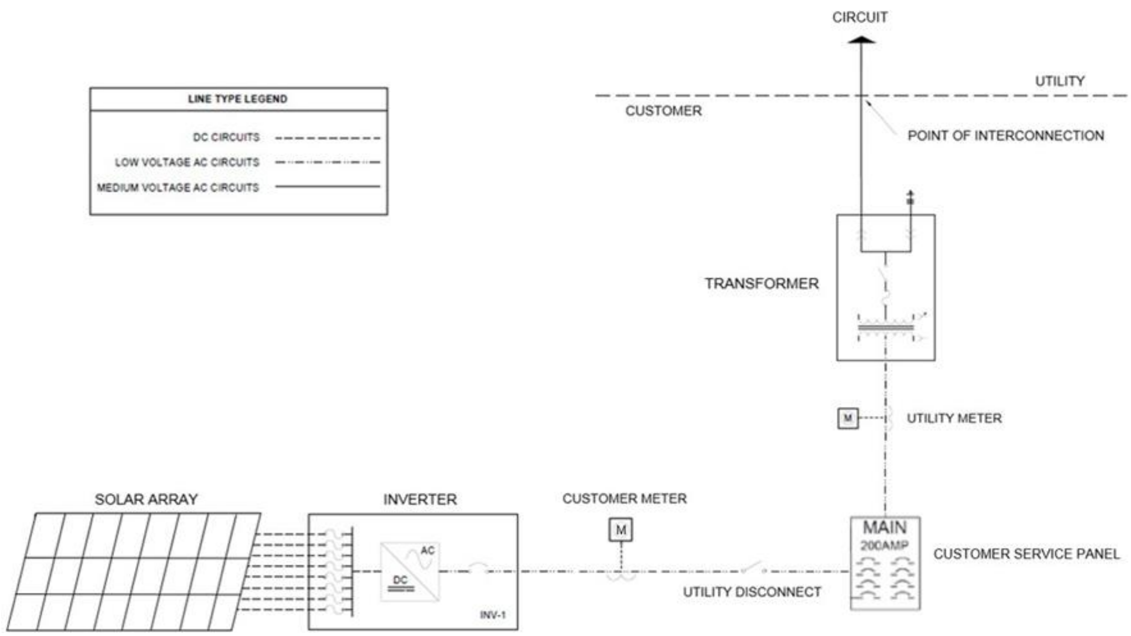

Figure 5. Example Single-Line Diagram for Net Metering Inverter-Based Project

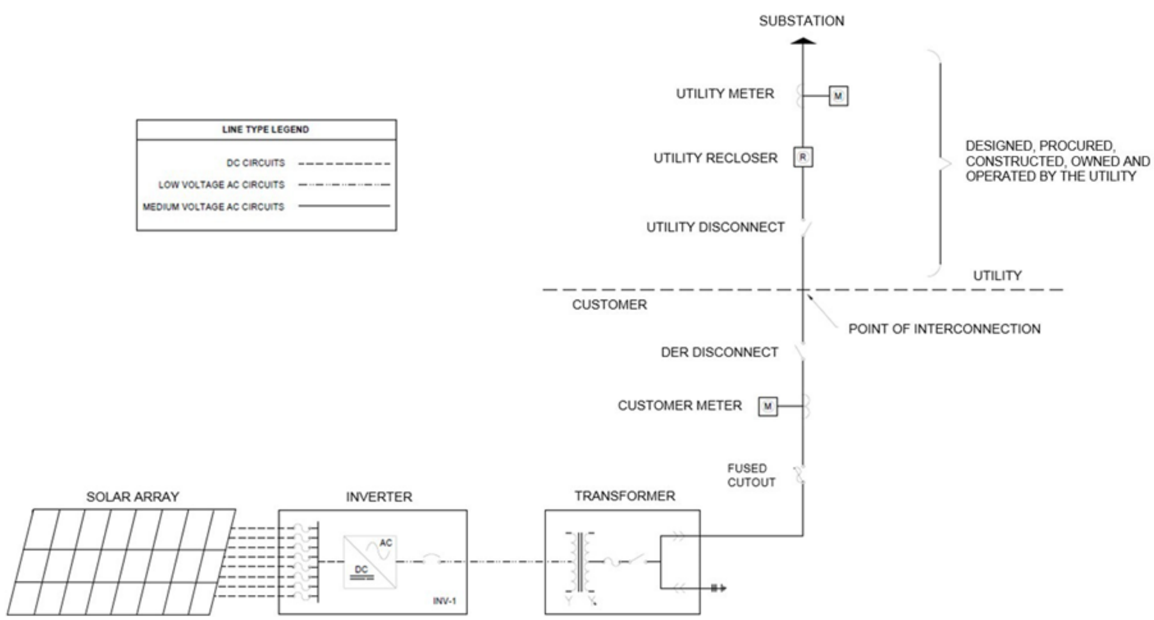

Figure 6. Example of Single-Line Diagram for Small Generator Inverter-Based Project

13 Small Generator Energization Checklist

✓	Item	Task	Completion Date (mm/dd/yyyy)	Completed By
☐	13.1	PGE drawing review complete.		
☐	13.2	PGE settings review complete (if Transfer Trip is required)		
☐	13.3	Electrical inspection complete (Green Tag)		
☐	13.4	PGE system upgrades complete (Compile task list for each project/DOR)		
☐	13.5	PGE mapping changes		
☐	13.6	Customer equipment one-lines input to MyWorld		
☐	13.7	Meter Enclosure: Verify installed equipment matches drawings and meter gear review.		
☐	13.8	PGE Instrument Transformers		
☐		Verify three CTs and three PTs installed		
☐		Inspect CT and PT mounting, polarity, and nameplate		
☐		Inspect CT and PT secondary wiring meter		
☐		Verify PT fuses and fuse clip assembly		
☐	13.9	PGE Meter		
☐		Meter numbers		
☐		Verify meter meets accuracy requirements		
☐		Verify meter communication with MV90		
☐		Greater than 3 MW		
☐		Verified Schneider Electric ION meter installed		
☐	13.10	PGE Distribution System Operations Approval for Energization		
☐		Distribution Operations Engineer approval		
☐		Grid Operations approval		

14 PGE Small Generator Witness Testing Prerequisites Checklist

These are the prerequisites for the witness testing of the site. Once all the steps below are completed the developer will be allowed to generate power for testing purposes.

✓	Item	Task	Completion Date (mm/dd/yyyy)	Completed By
☐	14-1	PGE to run approved switching sheet		
☐	14-2	Site protection system in-service		
☐	14-3	Transfer trip verified complete by PGE		
☐	14-4	Communications from PGE relay to developer device is functional		
☐	14-5	Developer device trips the proper protective device		
☐	14-6	Final as-left relay settings provided to PGE (.rdb)		
☐	14-7	Meter approved for Generation		
☐	14-8	PGE Distribution Systems Operations approval for generation		
☐	14-9	Distribution Operations Engineer approval		
☐	14-10	Grid Operations approval		

15 PGE Small Generator Witness Testing Checklist

PGE will use the form below to conduct its witness testing of the site. Once all the steps below are completed, PGE will prepare the letter authorizing Permission to Operate.

✓	Item	Task	Completion Date (mm/dd/yyyy)	Completed By
☐	15-1	As-built drawings provided (.pdf)		
☐	15-2	Proper signs are installed on the gate and switchgear including emergency contact information on gate		
☐	15-3	PGE locks are installed on all equipment and gates [include locations]		
☐	15-4	AC Disconnect is in place and properly labeled		
☐	15-5	Inverters and Step-Up Transformer match submittal documentation		
☐	15-6	Anti-islanding test is performed (Meterman to check COMM after test completed)		
☐	15-7	PGE Operations approval for Permission to Operate		
☐	15-8	Distribution Operations Engineer approval		
☐	15-9	Grid Operations approval		
☐	15-10	PPA Owner approval		

Appendix A Small Generator Interconnection

A.1 Overview of Steps for Small Generator Interconnections

The flow chart in Figure 7 provides a basic sequencing of steps involved in the interconnection of small generator DER on the PGE system. This chart begins with submission of the interconnection application by the applicant to PGE's secure, web-based PowerClerk portal. The chart is provided for illustrative purposes only. Small generator applicants must follow the interconnection procedures described in OAR 860-082 (small generator), as implemented by PGE consistent with pertinent technical standards and good utility practice.

Moreover, the duration and requirements of any individual step in the flow chart can vary widely between applicants based upon their DER nameplate rating and facility type, application tier, DER design, conditions at the proposed POI, responsiveness to PGE information requests, and other factors.

See Section 2.3.5, Initial Review Timelines, and Section 3.4, Study Types, for descriptions of time requirements for basic steps in the interconnection processes for small generator Tier 1, Tier 2, Tier 3, and Tier 4 DERs.

Figure 7. Overview Flow of Small Chart Generator Interconnection Process

A.2 Tables with Timeframes Specific to Small Generator Interconnections

The following four tables describe major steps and time requirements in the interconnection of small generator DER. The tables are provided for illustrative purposes only. Small generator applicants must follow the interconnection procedures described in OAR 860-082 (small generator) as implemented by PGE consistent with pertinent technical standards and good utility practice.

Table 10.Summary of Interconnection Steps and Timing Specific to Tier 1 Small Generator Applications

General Process Overview for Small Generator Interconnection—Tier 1	
Application	PGE to give notice to the applicant within 10 business days of whether the application is complete. If the application is incomplete, PGE to provide list of information needed to complete the application. Applicant to provide the requested information within 10 business days of receipt of the PGE list or the application is withdrawn.
Interconnection Studies	PGE to analyze the interconnection request based on the criteria listed in OAR 860-082-0045 and good utility practice. If a small generator facility is not approved under the Tier 1 interconnection screening procedure, PGE will provide a Screen Failure report with a written explanation of the reason for denial. The applicant may then request an Applicant Options Meeting, request PGE to complete a Supplemental Review, or submit a new application under the Tier 4 procedures. When a higher-queued interconnection request withdraws from the queue, PGE reserves the right to restudy a project as the interconnection requirements may have changed.
Interconnection Agreement	If the proposed interconnection is approved and requires no construction of facilities by PGE, PGE must provide the applicant an executed interconnection agreement no later than five business days after approving the interconnection. If the proposed interconnection is approved and requires construction of facilities, PGE must provide the applicant an executed interconnection agreement, along with a non-binding good faith cost estimate and construction schedule for any required upgrades, no later than 15 business days after approving the interconnection. Applicant to execute the interconnection agreement within 15 business days of receipt or the application is withdrawn.
Commissioning	Applicant to provide PGE written notice at least 20 business days before the planned commissioning for the small generator facility. PGE has the option of conducting a witness test at a mutually agreeable time within 10 business days of the scheduled commissioning. PGE to provide written notice to the applicant indicating whether PGE plans to conduct a witness test or waive the witness test. If PGE notifies the applicant that it plans to conduct a witness test but fails to conduct the witness test within 10 business days of the receipt of the certificate of completion or within a time otherwise agreed upon by applicant and PGE, the witness test is waived. If the witness test is conducted and is not acceptable to PGE, PGE to provide written notice to the applicant describing the deficiencies within 5 business days of conducting the witness test. PGE to provide the applicant 20 business days from the date of the applicant's receipt of the notice to resolve the deficiencies. If the applicant fails to resolve the deficiencies to the satisfaction of PGE within 20 business days, the application is withdrawn.

Table 11.Summary of Interconnection Steps and Timing Specific to Tier 2 Small Generator Applications

General Process Overview for Small Generator Interconnection—Tier 2	
Application	PGE to give notice to the applicant within 10 business days of whether the application is complete. If the application is incomplete, PGE to provide list of information needed to complete the application. Applicant to provide the requested information within 10 business days of receipt of the PGE list or the application is withdrawn.
Scoping Meeting	PGE to schedule the scoping meeting within 10 business days of notifying the applicant that the application is complete.
Interconnection Studies	PGE to analyze the interconnection request based on the criteria listed in OAR 860-082-0050 and good utility practice. If a small generator facility is not approved under the Tier 2 interconnection screening procedure, PGE will provide a Screen Failure report with a written explanation of the reason for denial. The applicant may then request an Applicant Options Meeting, request PGE to complete a Supplemental Review, or submit a new application under the Tier 4 procedures. When a higher-queued interconnection request withdraws from the queue, PGE reserves the right to restudy a project as the interconnection requirements may have changed.
Interconnection Agreement	If the proposed interconnection is approved and requires no construction of facilities by PGE, PGE must provide the applicant an executed interconnection agreement no later than five business days after approving the interconnection. If the proposed interconnection is approved and requires construction of facilities, PGE must provide the applicant an executed interconnection agreement, along with a non-binding good faith cost estimate and construction schedule for any required upgrades, no later than 15 business days after approving the interconnection. Applicant to execute the interconnection agreement within 15 business days of receipt or its application is withdrawn.
Commissioning	Applicant to provide PGE written notice at least 20 business days before the planned commissioning for the small generator facility. PGE has the option of conducting a witness test at a mutually agreeable time within 10 business days of the receipt of the certificate of completion. PGE to provide written notice to the applicant indicating whether PGE plans to conduct or waive the witness test. If PGE notifies the applicant that it plans to conduct a witness test but fails to conduct the witness test within 10 business days of the receipt of the certificate of completion or within a time otherwise agreed upon by applicant and PGE, the witness test is waived.

Table 12.Summary of Interconnection Steps and Timing Specific to Tier 3 Small Generator Applications

General Process Overview for Small Generator Interconnection—Tier 3	
Application	PGE to give notice to the applicant within 10 business days of whether the application is complete. If the application is incomplete, PGE to provide list of information needed to complete the application. Applicant to provide the requested information within 10 business days of receipt of the PGE list or the application is withdrawn.
Scoping Meeting	PGE to schedule the scoping meeting within 10 business days of notifying the applicant that the application is complete.
Interconnection Studies	PGE to analyze the interconnection request based on the criteria listed in OAR 860-082-0055 and good utility practice. If a small generator facility is not approved under the Tier 3 interconnection screening procedure, PGE will provide a Screen Failure report with a written explanation of the reason for denial. The applicant may then request an Applicant Options Meeting, request PGE to complete a Supplemental Review, or submit a new application under the Tier 4 procedures. When a higher-queued interconnection request withdraws from the queue, PGE reserves the right to restudy a project as the interconnection requirements may have changed.
Interconnection Agreement	If the proposed interconnection is approved and requires no construction of facilities by PGE, PGE must provide the applicant an executed interconnection agreement no later than five business days after approving the interconnection. If the proposed interconnection is approved and requires construction of facilities, PGE must provide the applicant an executed interconnection agreement, along with a non-binding good faith cost estimate and construction schedule for any required upgrades, no later than 15 business days after approving the interconnection. Applicant to execute the Interconnection Agreement within 15 business days of receipt or its application is withdrawn.
Commissioning	Applicant to provide PGE written notice at least 20 business days before the planned commissioning for the small generator facility. PGE has the option of conducting a witness test at a mutually agreeable time within 10 business days of the receipt of the certificate of completion. PGE to provide written notice to the applicant indicating whether PGE plans to conduct or waive the witness test. If PGE notifies the applicant that it plans to conduct a witness test but fails to conduct the witness test within 10 business days of the receipt of the certificate of completion or within a time otherwise agreed upon by applicant and PGE, the witness test is waived. If the witness test is conducted and is not acceptable to PGE, PGE to provide written notice to the applicant describing the deficiencies within 5 business days of conducting the witness test. PGE to provide the applicant 20 business days from the date of the applicant's receipt of the notice to resolve the deficiencies. If the applicant fails to resolve the deficiencies to the reasonable satisfaction of PGE within 20 business days, the application is withdrawn.

Table 13.Summary of Interconnection Steps and Timing Specific to Tier 4 Small Generator Applications

General Process Overview for Small Generator Interconnection—Tier 4	
Application	PGE to give notice to the applicant within 10 business days of whether the application is complete. If the application is incomplete, PGE to provide list of information needed to complete the application. Applicant to provide the requested information within 10 business days of receipt of the PGE list or the application is withdrawn.
Scoping Meeting	PGE to schedule the scoping meeting within 10 business days of notifying the applicant that the application is complete. PGE to give notice of approval of the application to the applicant within 15 business days of scoping meeting if no studies are necessary, no system upgrades or facility modifications are required, and no safety or reliability issues are identified.
Feasibility Study	PGE to deliver the Feasibility Study Agreement to the applicant within 5 business days of the scoping meeting. Applicant to execute the Feasibility Study Agreement within 15 business days or its application is withdrawn. The timeline for the completion of the study will be included within the study agreement. PGE to provide the study results to the applicant within 5 business days of study completion.
System Impact Study	PGE to deliver the System Impact Study Agreement to the applicant within 5 business days of completing the feasibility study or following the scoping meeting date if no feasibility study is required or the need for a feasibility study is waived. Applicant to execute the System Impact Study Agreement within 15 business days of receipt or its application is withdrawn. The timeline for the completion of the study will be included within the study agreement. PGE to give notice of approval of application to the applicant within 15 business days of completion of the system impact study if all criteria are met and no interconnection facilities or system upgrades are required. PGE to provide the study results within 5 business days of study completion.
Facilities Study	PGE to deliver the Facilities Study agreement to the applicant within 5 business days after the scoping meeting if no feasibility study or system impact study is needed. Applicant to execute the Facilities Study Agreement within 15 business days of receipt or its application is withdrawn. The timeline for the completion of the study will be included within the study agreement. PGE to give notice of approval of application within 15 business days after the applicant agrees to pay for the interconnection facilities and system upgrades identified in the facilities study. PGE to provide the study results to the applicant within 5 business days of study completion.
Interconnection Agreement	If the proposed interconnection is approved and requires no construction of facilities by PGE, PGE must provide the applicant an executed interconnection agreement no later than five business days after approving the interconnection. If the proposed interconnection is approved and requires construction of facilities, PGE must provide the applicant an executed interconnection agreement, along with a non-binding good faith cost estimate and construction schedule for any required upgrades, no later than 15 business days after approving the interconnection. Applicant to execute the Interconnection Agreement within 15 business days of receipt or its application is withdrawn.

General Process Overview for Small Generator Interconnection—Tier 4	
Commissioning	Applicant to provide PGE written notice at least 20 business days before the planned commissioning for the small generator facility. PGE has the option of conducting a witness test at a mutually agreeable time within 10 business days of the receipt of the certificate of completion. PGE to provide written notice to the applicant indicating whether PGE plans to conduct a witness test or waive the witness test. If PGE notifies the applicant that it plans to conduct a witness test but fails to conduct the witness test within 10 business days of the receipt of the certificate of completion or within a time otherwise agreed upon by applicant and PGE, the witness test is waived. If the witness test is conducted and is not acceptable to PGE, PGE to provide written notice to the applicant describing the deficiencies within 5 business days of conducting the witness test. PGE to provide the applicant 20 business days from the date of the applicant's receipt of the notice to resolve the deficiencies. If the applicant fails to resolve the deficiencies to the reasonable satisfaction of PGE within 20 business days, the application is withdrawn.

A.3 DER Transfer Trip Settings

Table 14. Mirrored Bits Sent from PGE to DER (as seen by the DER)

Word Bit	PGE Initiating Action	DER Resulting Action	Time Delay on Resulting Action
RMB1A	Feeder Trip	Initiates DTT of DER	0
RMB2A	Feeder 52a	DER must trip if this signal is lost	0.1 seconds
RMB3A	DER TT Enabled	DER must cease generating	60 seconds
RMB4A	DER DTT w/o Feeder Trip	Initiates DTT of DER	0

Table 15. Mirrored Bits Sent from DER to PGE

Word Bit	DER Site Initiating Actor	PGE Resulting Action
TMB1A	DER Main Breaker 52a	Status only
TMB2A	Reserved for Second 52a	Status only
TMB3A	DER Online and In Parallel (See Additional Logic section if using current or power supervision)	Block feeder breaker close
TMB4A	Reserved for Second Online and in Parallel	Block feeder breaker close

Table 16. DER Transfer Trip Communications Settings

Setting	Setting Value	Description
RXDFLT	000000X0	RMB2A (52A) defaults to last received value upon loss of communications—all other RMBs default to 0.
SPEED	19200	Communications port baud rate
PROTO	MB8A	Port protocol
RMB1PU	2	RMB1A Pickup Debounce (messages)
RMB1DO	8	RMB1A Dropout Debounce (messages)
RMB2PU	2	RMB2A Pickup Debounce (messages)
RMB2DO	8	RMB2A Dropout Debounce (messages)
RMB3PU	2	RMB3A Pickup Debounce (messages)
RMB3DO	8	RMB3A Dropout Debounce (messages)
RMB4PU	2	RMB4A Pickup Debounce (messages)
RMB4DO	8	RMB4A Dropout Debounce (messages)
RBADPU	60	Mirrored Bits RX Bad Pickup Time (seconds)
CBADPU	1000	Mirrored Bits Channel Bad Pickup (parts per million)

Table 17. DER Transfer Trip Additional Logic

Setting	Setting Value	Description
Loss of Communications	SVn = !ROKA*(CBADA+RBADA)	Channel fail with security restraints. Recommend 30 second pickup and 1 second dropout. Results in soft shutdown if DER is capable of a soft shutdown in under 2 minutes—otherwise results in DER trip.
Relay Fail Alarm	ALARM	Indicates relay has a problem or has powered down. Results in soft shutdown if DER is capable of a soft shutdown in under 2 minutes—otherwise results in DER trip.
Event Trigger	CLOSE+/52A	Relay auto generates event report for Trip, this will also generate an event report for Close or closing the breaker.
Load Detector	Positive sequence current I1_MAG comparison against current setpoint (SEL-7xx only) or 3-phase directional power element set in direction of power export.	Indicates that the DER is exporting power. 5 second dropout timer. Timer variable supervises TMB3A. Setpoint of power or current supervision equivalent to 250 kW or less.

Table 18. DER Transfer Trip Recommended Display Points

Display Point	Logic	Description
TT Disabled/Enabled	RMB3A	Transfer Trip Enabled
Utility 52A	RMB2A	Utility Breaker closed
DER Online/Parallel	TMB3A	DER running and in parallel
Loss of Comms	!ROKA	Loss of Comms

Table 19. DER Transfer Trip Recommended SER Points

Word Bit	Description
TMB1A	DER Main Breaker 52a
TMB2A	Reserved for Second 52a
TMB3A	DER Online and In Parallel
TMB4A	Reserved for Second Online and in Parallel
RMB1A	Feeder Trip
RMB2A	Feeder 52a
RMB3A	DER TT Enabled
RMB4A	DER DTT w/o Feeder Trip
RBADA	Mirrored Bits RX Bad Pickup Time
CBADA	Mirrored Bits Channel Bad Pickup
SVn	Loss of Communications
DER 52a	DER Main Breaker 52a
TRIP	Relay Trip
Elements in Trip Equation	Under/over voltage, frequency, overcurrent, negative sequence elements
Inputs	Inputs used
Outputs	Outputs used
Close	Relay Close
Elements in Close Equation	Close permissive

NOTE: If the site has alternate service arrangements that allow it to switch on its own, the DER is not allowed to run on the alternate feed unless otherwise agreed to by PGE. This must be documented in the Interconnection Agreement.

NOTE: If there is an intermediate device (for example, PLC) between the relay and the DER that controls the DER, there should be delay in the common fail and relay alarm outputs from the relay to the intermediate device. The delay will prevent unwanted shutdown of the DER when changing settings on the relay.

A.4 Commissioning and Witness Test Checklist for Small Generator Applicants

PGE provides the tables in Section 11, As-Built Documentation and Interconnection Checklist, to help applicants assemble required information for the commissioning (or energization) of their DER. The information should be sent to PGE at least two weeks prior to planned commissioning of the DER on the PGE system.

Appendix B Definitions

B.1 Glossary

The definitions below define a selection of key terms used in this document and was drawn primarily from OAR 860-082 (small generator and community solar) and OAR 860-039 (net metering). This is not a comprehensive glossary. Additional definitions are available in those two OAR documents and in IEEE documents (e.g., IEEE 1547-2018 and IEEE 1547.1-2005).

Table 20.Glossary

Term	Definition
Abnormal Operating Performance Category	The grouping for a set of requirements that specify technical capabilities and settings for a DER under abnormal operating conditions, i.e., outside the continuous operation region.
Adverse System Impact	A negative effect caused by the interconnection of a DER that may compromise the safety, reliability, or power quality of a distribution or transmission system.
Affected System	A distribution or transmission system, not owned or operated by the interconnecting public utility, which may experience an adverse system impact from the interconnection of a DER.
Applicant or Customer	An entity or person that seeks to interconnect a DER to the PGE system.
Area Network	See definition for secondary grid network.
Backfeed	Real power watt flow towards the substation.
Bidirectional	A device is considered to be bidirectional only if the device is capable of operating in two or more directions. For example, if a recloser bank's settings are not set up for bidirectional protective coordination, then the device would be considered unidirectional. In another example, if a voltage regulator bank does not have the appropriate control for bidirectional or co-generation operation, then the voltage regulator bank is considered unidirectional.
Certificate of Completion	A document signed by an applicant and PGE attesting that a DER is complete, meets the applicable requirements of the interconnection rules, and has been inspected, tested, and certified as physically ready for operation on the PGE system. A certificate of completion includes the "as built" specifications and initial settings for the DER and its associated interconnection equipment. This document is also referred to as a "permission to operate."
Distributed Energy Resources (DER)	Facilities capable of delivering electric power, including both generators and energy storage technologies, that can be interconnected with the PGE system or connected to a host facility within the PGE system. In contexts other than this document's focus on interconnection, distributed energy resources may include additional technologies that customers may implement on the PGE system such as electric vehicles, controllable loads, and energy efficiency measures.
Electric Power System (EPS)	Facilities that deliver electric power to a load.
Electric Service Requirements (ESR) book	PGE's book of requirements for obtaining electric service for low-voltage services (services less than 600 V). This book applies to new service, relocated services, rewired services, and temporary services.
Enter Service	Begin operation of the DER with an energized Area EPS.

Term	Definition
Export Capacity	The amount of power that can be transferred from the Distributed Energy Resource facility to the distribution system. Export capacity is either the nameplate rating, or a lower amount if limited using an acceptable means identified In Section 3.5.4, Limited Export or Non-Export Requirements.
Fault Current	An electrical current that flows through a circuit during a fault condition. A fault condition occurs when one or more electrical conductors contact ground or each other. Types of faults include phase to ground, double-phase to ground, three-phase to ground, phase to phase, and three-phase. PGE uses the term “fault current” interchangeably with “short-circuit current.”
Good Utility Practice	A practice, method, policy, or action engaged in or accepted by a significant portion of the electric industry in a region, which a reasonable utility official would expect, in light of the facts reasonably discernable at the time, to accomplish the desired result reliably, safely, and expeditiously.
Interconnection Agreement (IA)	A contract between an applicant and PGE governing the interconnection of a DER to the PGE system and the ongoing operation of the DER after it is energized on the PGE system.
Interconnection Facilities	The facilities and equipment required by PGE to accommodate the interconnection of a DER to the PGE system and used exclusively for that interconnection. These facilities do not include “system upgrades.”
Large Generator Applicant	A proposed DER facility that is above 10 MW in nameplate rating, seeks to interconnect to the PGE system, and is not under FERC jurisdiction. Such applicants are subject to PGE’s large generator interconnection requirements.
Medium Voltage Requirements book	PGE’s book of requirements for obtaining electric service for medium voltage services (services 600 V to 35 kV).
Minor Equipment Modification	A change to a small generator or CSP DER or its associated interconnection equipment that: ▪ Includes a change or replacement of equipment that is a like-kind substitution in size, ratings, impedances, efficiencies, or capabilities of the equipment specified in the original interconnection application. Minor variations that do not affect safety, performance, or interoperability are acceptable; ▪ Includes a replacement of existing inverters with new inverters that conform to standards in effect at the time of replacement; ▪ Includes a reduction in the nameplate rating and/or export capacity of the small generator facility of 10 percent or less; or ▪ For changes not specified in subsections (a) through (c) of this definition, the change must not, in the interconnecting public utility’s reasonable opinion, have a material impact on the safety or reliability of the public utility’s transmission or distribution system or an affected system.
Momentary Cessation	Temporarily cease to energize an EPS, while connected to the Area EPS, in response to a disturbance of the applicable voltages or the system frequency, with the capability of immediate Restore Output of operation when the applicable voltages and the system frequency return to within defined ranges.
Nameplate Rating	The sum total of maximum rated power output of all of a small generator facility’s constituent generating units and/or energy storage systems as identified on the manufacturer nameplate in Alternating Current (AC), regardless of whether it is limited by any approved means. For a generating unit that uses an inverter to change direct current energy supplied to an AC quantity, the nameplate rating will be the manufacturer’s AC output rating for the inverter(s).

Term	Definition
Net Metering Applicant	A proposed DER facility that seeks to be directly interconnected to a PGE end-use electricity customer's premises, is intended primarily to offset part or all of that customer's electricity requirements from PGE and can operate in parallel with the PGE system. A fuller definition of "net metering" is available in Oregon Revised Statutes 757.300. Net metering DER projects are limited to a capacity of 25 kW or less in nameplate rating for residential customers and 2 MW or less in nameplate rating for non-residential customers.
Normal Operating Performance Category	The grouping for a set of requirements that specify technical capabilities and settings for DER under normal operating conditions, i.e., inside the continuous operation region.
Parallel Operations	Occurs when a DER is serving as a source of electric power for greater than 100 milliseconds while connected to the PGE system.
Permission to Operate	See definition for Certificate of Completion.
PGE System	Electrical facilities owned by PGE. These facilities can deliver electricity from either transformation points on the transmission system or electricity directly injected into the distribution facilities to points of connection on an end-use customer's premises.
Point of Common Coupling (PCC)	The point beyond a net metering DER's meter where the DER connects with the PGE system.
Point of Interconnection (POI)	The point where a small generator or CSP DER is electrically connected to the PGE system. This term has the same meaning as "point of common coupling" as defined in Section 3.1 of IEEE 1547-2018. This term does not, however, have the same meaning as "point of common coupling" as defined in OAR 860-039-0005 for net metering DERs.
Queue Position	The rank of an interconnection application determined by PGE to have complete information, relative to all other applications determined by PGE to be complete at a given location on the PGE system. Queue position is established based on the date and time that PGE receives the completed applications, including application fees.
Secondary Grid Network	A type of distribution system served by multiple transformers interconnected in an electrical network circuit to provide high reliability of service.
Secondary Voltage	The voltage from the primary distribution line that has been reduced in a PGE owned step-down service transformer.
Small Generator Applicant	A proposed DER facility of up to 10 MW in nameplate rating seeking to interconnect to the PGE system that does not meet the standards for a net metering applicant and is not under FERC jurisdiction.
Spot Network	A type of distribution or transmission system that uses two or more intertied transformers protected by network protectors to supply an electrical network circuit. A spot network may be used to supply power to a single customer or a small group of customers.
System Impact Study	A detailed study conducted after application fails Tier 1 through Tier 3 screens in OAR 860-082 and moves to the Tier 4 application. The basic requirements of this type of study can be found in OAR 860-082.
System Upgrade	An addition or modification to PGE's distribution or transmission system or to an "affected system" of another public utility that is required to accommodate the interconnection of a DER.

B.2 Acronyms

The definitions used in this document are consistent with the IEEE 1547-2018, IEEE 1547.1-2005, and OAR 860-039 and OAR 860-082.

Table 21. Acronyms List

Acronym	Definition
ac	Alternating Current
AHJ	Authority Having Jurisdiction
ANSI	American National Standards Institute
BPS	Bulk Power System
CSP	Community Solar Program
CT	Current Transformer
dc	Direct Current
DER	Distributed Energy Resource
DNP	Distributed Network Protocol
EPS	Electric Power System
ES	Energy Storage
ESR	Electric Service Requirements
EUSERC	Electric Utility Service Equipment Requirements Committee
FERC	Federal Energy Regulatory Commission
IEEE	Institute of Electrical and Electronics Engineers, Inc.
kV	Kilovolt(s)
kVA	Kilovolt-amps
kW	Kilowatt(s)
kWh	Kilowatt-hour(s)
LTC	Load Tap Changer
MBTT	Mirrored Bits Protocol for Transfer Trip
ms	Milliseconds
MVA	Megavolt amps
MW	Megawatt(s)
NERC	North American Electric Reliability Council
NFPA	National Fire Protection Association
NWPP	Northwest Power Pool
OAR	Oregon Administrative Rules
OPUC	Public Utility Commission of Oregon
PCC	Point of Common Coupling
PGE	Portland General Electric Company
POI	Point of Interconnection
PPA	Power Purchase Agreement
PT	Potential Transformer
PU	Per Unit (1.0 is equal to 100% of nominal characteristic, i.e., voltage)
PV	Photovoltaic

Acronym	Definition
QF	Qualifying Facility
SCADA	Supervisory Control and Data Acquisition
SEL	Schweitzer Engineering Laboratories
V	Volt
WECC	Western Electric Coordinating Council

Appendix C References

The external sources referenced in this document are listed below with their URLs. The URLs represented the web locations of the references at the time PGE completed this edition of its interconnection standards, but the URLs may have changed since the time this document was completed.

ANSI C84.1-2016	Electric Power Systems and Equipment – Voltage Ratings (60 Hz)*
IEEE 141-1993	Recommended Practice for Electric Power Distribution for Industrial Plants**
IEEE 519-2014	Recommended Practice and Requirements for Harmonic Control in Electric Power Systems**
IEEE 1453-2015	Recommended Practice for the Analysis of Fluctuating Installations on Power Systems**
IEEE 1547-2003	Standard for Interconnecting Distributed Resources with Electric Power Systems** (only applicable to legacy systems installed before June 1, 2024)
IEEE 1547.1-2005	Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems**
IEEE 1547-2018	Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces**
IEEE C37.90.1-2002	Standard Surge Withstand Capability (SWC) Tests for Relays and Relay Systems Associated with Electric Power Apparatus**
IEEE C57.13-2016	Standard Requirements for Instrument Transformers**
IEEE C62.41.2-2002	Recommended Practice on Characterization of Surges in Low-Voltage (1000 V and less) AC Power Circuits**
NFPA 70®	National Electrical Code®
OPUC OAR 860-039	Net Metering Rules
OPUC OAR 860-082	Small Generator Interconnection Rules
OPUC OAR 860-088	Community Solar Program Rules
OPUC Order Number 10-132	Oregon Standard Interconnection Procedures and Agreements Adopted for Large Qualifying Facilities
PGE ESR	Electric Service Requirements
PGE MSR	Medium Voltage Requirements
PGE QF	Small Generator Interconnection Program Interconnection Technical Requirements
PGE CSP	Community Solar Program
UL 1741	Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources***

* Available for subscription.
** Available for purchase or subscription.
*** Available for purchase.

Appendix D Smart Inverter Requirements

D.1 Introduction

The following are the preferred default inverter settings for Distributed Energy Resources (DER) interconnections to Portland General Electric's (PGE) Electric Distribution System in compliance with IEEE 1547-2018. Compliance with IEEE 1547-2018 is recognized when the inverter has been tested and certified by a nationally recognized testing laboratory (NRTL) to the UL 1741-SB. Equipment installed before August 15, 2024 will be considered legacy and are not required to conform to IEEE 1547-2018 requirements, as long as the system has been lab-tested, certified, and labeled as such by a NRTL in accordance with IEEE 1547-2003. If a system or its components installed before August 15, 2024 is replaced, the new system or components shall be compliant with the IEEE 1547-2018 standard and be programmed with the default standards applicable at the time of replacement or the equipment shall be reviewed by PGE as a "like-kind" equipment to accommodate warranty replacements, system compatibility issues for larger integrated DER systems, or previously acquired spare parts.

This document is intended to be used as a complement to PGE's Electric Service Requirements (ESR) for installations less than 600 V and PGE's Medium Voltage Requirements for services greater than 600 V, other applicable industry standards required to ensure safety, reliability, and compliance (i.e., National Electric Code [NEC] and National Electric Safety Code [NESC]), and all IEEE standards and UL Standards as stated in Oregon Administrative Rules (OAR) 860-039 and 860-082. This document contains PGE's utility-specific standards and requirements and is only applicable to DER applications of generating facilities with a nameplate rating up to and including 10 MW connecting to PGE's distribution system.

The settings contained in this document are to be considered IEEE 1547-2018 compliant default settings for most, but not all, Category B (typically inverter-based) DER interconnection. Category B is one of two normal operating performance categories described in the following sections. All settings will be specified to the customer using the EPRI common-file format (CFF) and applied settings will be returned to utility once the system is installed all in .csv file format. Category A When an application for Category B DERs fail Tier 1, Tier 2, or Tier 3 screens, or is a Tier 4 applicant, where either a supplemental review or detailed study is required, PGE may obligate the interconnection to implement different inverter settings than those listed here. PGE reserves the right to modify these default settings as PGE gains more experience with how advanced inverters operate and interact with PGE's distribution system, especially when reliability and safety are of concern. However, all changes to settings will be compliant with IEEE 1547-2018 and/or OAR 860-039 and OAR 860-082.

D.2 Performance Categories

The IEEE 1547-2018 standard performance categories specify required capability for reactive power performance, voltage regulation performance, and response to abnormal conditions. Performance categories describe minimum equipment capability and the required ranges of allowable settings. Category A and B specify DER reactive power capability and voltage regulation performance requirements during normal operating conditions. Category A and B are defined in the following sections consistent with IEEE 1547-2018 definitions:

D.2.1 Category A

Category A covers minimum performance capabilities needed for Area EPS voltage regulation and are reasonably attainable by all state-of-the-art DER technologies. This level of performance is deemed adequate for applications where the DER penetration in the distribution system is lower, and where the DER power output is not subject to frequent large variations.

D.2.2 Category B

Category B covers all requirements within Category A and specifies supplemental capabilities needed to adequately integrate the DER in local area EPS where the DER penetration is higher or where the DER power output is subject to frequent large variations.

For the purposes of this appendix, only Category B settings are specified.

Categories I, II, and III separate performance requirements for DER response into abnormal operating conditions based on system needs. Category III has the highest ride-through capability of all three abnormal operating condition categories. The abnormal operating categories are described as follows consistent with IEEE 1547-2018 category definitions.

I. Category I meets the minimum BPS essential needs and are reasonably attainable by all DER technologies that are in use today.

II. Category II meets all BPS needs related to stability and reliability and coordinates with existing reliability standards.

III. Category III meets all BPS reliability needs and also introduces ride-through requirements aimed at addressing high DER penetration.

D.2.3 Performance Categories Assignments

This document will only assign categories for inverter-based DER. All inverter-based DERs on PGE's distribution system shall meet Category B performance requirements for normal operating conditions and Category III for abnormal operating conditions.

D.3 Reactive Power Capability and Voltage/Power Control Performance

Inverter-based DER shall be capable of IEEE 1547-2018 Category B voltage and reactive/active power control functions including constant power factor mode, voltage-reactive power mode, active power-reactive power mode, constant reactive power mode, and voltage-active power mode.

DER shall meet the performance categories and settings specified in IEEE 1547-2018, this document, and other industry standards for each voltage and reactive/active power control function. The required default settings for each voltage and reactive/active power control function will depend greatly on the size and location of the DER within the distribution feeder. DERs that proceed to the Tier 4 application may be required to use specified settings other than these default settings in this document.

D.3.1 Reactive Power Capability of the DER

DER reactive power capability shall be compliant with Section 5.2 of IEEE 1547-2018 for Category B DERs and be available for use by the PGE operator.

D.3.2 Constant Power Factor

PGE requires the settings for Constant Power Factor control to be disabled.

D.3.3 Voltage-Reactive Power Control (Volt-Var)

PGE requires the settings for Voltage-Reactive Power Control to be enabled, unless otherwise specified in the Interconnection Agreement. The Voltage-Reactive Power mode default settings shall be set to the IEEE 1547-2018 default settings unless otherwise specified by the outcome of a Tier 4 application.

Table 22. Voltage-Reactive Power Control Inverter-Based DER Settings

Voltage-Reactive Power Parameters	Inverter-based DER Default Settings
V_{Ref}	V_N
V_1	$V_{Ref} – 0.08\ V_N$
V_2	$V_{Ref} – 0.02\ V_N$
V_3	$V_{Ref} + 0.02\ V_N$
V_4	$V_{Ref} + 0.08\ V_N$
Q_1	44% of nameplate apparent power rating, injection
Q_2	0
Q_3	0
Q_4	44% of nameplate apparent power rating, absorption
Open Loop Response Time	5 s

NOTE: All DER shall utilize a fixed reference voltage V_{Ref}, V_N is assumed to be set at DER nominal AC operating voltage, and lastly that the DER reactive power capability may be reduced at lower voltage.

D.3.4 Voltage-Active Power Control (Volt-Watt)

PGE requires the settings for voltage-active power control to be enabled[2] for IEEE 1547-2018 Category B systems, unless otherwise specified by the interconnection agreement. The voltage-active power mode default setting shall be set to the IEEE 1547-2018 Category B default setting as shown in Table 23, unless otherwise specified by the outcome of a Tier 4 application.

Table 23. Voltage-Active Power Control for Generating-Only DERs

Voltage-Active Power Parameters	Default Setting
V_1	$1.06\ V_N$
P_1	P_{rated}
V_2	$1.1\ V_N$
P_2	0
Open Loop Response Time	10 s

NOTE: P_{rated} is the maximum active power output in PU of the DER rating.

[2] Several studies, including those from NREL and EPRI, have shown that having this volt-watt “backstop” has negligible impacts on active power curtailment, except for when there is an existing voltage issues that the utility bears responsibility for mitigating.

D.3.5 Active Power-Reactive Power Control

PGE requires the settings for active power-reactive power control to be disabled.

D.3.6 Constant Reactive Power Control

PGE requires the settings for constant reactive power control to be disabled.

D.4 Response to Abnormal Conditions

Voltage disturbance ride-through and frequency disturbance ride-through settings shall be enabled by the inverter-based DER interconnection on PGE's Distribution System. Inverter-based DERs shall be able to meet the requirements of IEEE 1547-2018 Abnormal Performance Category III for response to abnormal conditions. If exceptions apply per IEEE 1547-2018 Section 6.4.2.1 and 6.5.2.1, the voltage and frequency ride-through requirements specified in this section do not apply and DER may cease to energize the PGE's distribution system and trip without limitations.

D.4.1 Abnormal Voltages

For inverter-based DERs, the DER shall trip for the following voltage conditions as shown in Table 24, which is consistent with the Category III DER default settings found in Table 13 of IEEE 1547-2018.

Table 24.Inverter-Based Category III DER Abnormal Voltage Shall Trip Response Settings

Shall Trip Function	Default Setting	
	Clearing Time (s)	Voltage (PU of Nominal Voltage)
UV1	21.0	0.88
UV2	2.0	0.50
OV1	13.0	1.10
OV2	0.16	1.20

The DER shall ride-through consecutive temporary voltage disturbances in accordance with IEEE 1547-2018 Section 6.4.2.5 requirements for Category III DER.

In IEEE 1547-2018 for Category III DER, Table 16 and Figures H.9 are additional references for abnormal voltage response settings.

D.4.2 Abnormal Frequency

For inverter-based DERs, the DER shall trip for abnormal frequency conditions as shown in Table 25, which is consistent with the Category III DER default settings found in Table 18 of IEEE 1547-2018.

Table 25.Inverter-Based Category III DER Abnormal Frequency Shall Trip Response Settings

Shall Trip Function	Default Setting	
	Clearing Time (s)	Frequency (Hz)
UF1	0.16	56.5
UF2	300	58.5
OF1	300	61.2
OF2	0.16	62.0

Inverter-based DERs shall comply with the rate of change of frequency (ROCOF) ride-through performance requirements per IEEE 1547-2018 Section 6.5.2.5 and the voltage phase angle changes ride-through requirements per IEEE 1547-2018 Section 6.5.2.6.

In IEEE 1547-2018 for Category III DER, Table 18 and Figures H.10 are additional references for abnormal frequency response settings.

D.4.3 FREQUENCY DROOP

Inverter-based DERs shall operate with a frequency droop during both low and high-frequency conditions as required by IEEE 1547-2018, Table 22. Inverter-based DER shall comply with the frequency droop default settings in Table 24 of IEEE 1547-2018.

Table 26.Inverter-Based DER Frequency Droop Settings

Parameter	Default Setting
db_{OF}, db_{UF} (Hz)	0.036
kOF, kUF	0.05
TResponse (s)	5

D.4.4 DYNAMIC VOLTAGE SUPPORT

Dynamic Voltage Support shall be disabled.

D.4.5 MOMENTARY CESSATION

For inverter-based DERs, the DER shall set the momentary cessation ride-through parameters to those provided below in Table 27 consistent with the Category III DER default settings found in Table 16 of IEEE 1547-2018.

Table 27.Inverter-Based DER Momentary Cessation Settings

Parameter	Default Setting (PU of Nominal Voltage)
MC HVRT	1.1
MC LVRT	0.5

In IEEE 1547-2018 for Category III DER, Table 16 and Figures H.9 are additional references for momentary cessation ride-through settings.

D.5 Communication Protocols and Ports Requirements

In Section 10 of IEEE 1547-2018, the following is applicable to communications interoperability functions. The application of these requirements will be determined by PGE.

- A DER shall have provisions for a local DER interface capable of communicating (local DER communication interface) to support the information exchange requirements specified in the IEEE 1547-2018 standard for all applicable functions that are supported in the DER.
- Under mutual agreement between PGE and the DER operator, additional communication capabilities are allowed.
- The decision to use the local DER communication interface or to deploy a communication system shall be determined by PGE.

- Emergency and standby DER are exempt as specified from the interoperability requirements specified in the IEEE 1547-2018 standard.

The interoperability requirements are still in development and will be provided at a later date.

D.6 Operations

D.6.1 Enter Service Parameters

Enter Service shall be enabled for inverter-based DER to connect to PGE's Distribution System. The DER is required to delay entry into service by an intentional minimum delay of 300 seconds followed by an active power ramp or an additional randomized time delay. Table 28 shows the default settings for the applicable voltage and frequency values that a DER must meet before entering service and energizing service to PGE's distribution feeder.

Table 28.Enter Service Criteria

DER Enter Service Criteria		
Voltage Within Range	Minimum Value	≥0.917 PU
	Maximum Value	≤1.05 PU
Frequency Within Range	Minimum Value	≥59.5 Hz
	Maximum Value	≤60.1 Hz

D.6.2 Ramp Rates

According to IEEE 1547-2018 Section 4.10.3 (c), after the minimum delay of the enter service requirements for service entry has elapsed, DERs shall ramp the active power output with a linear, or in a stepwise linear ramp. In a linear ramp, the DER should not output any more than 20% of DER nameplate in any single step, whereas in a stepwise linear ramp the rate of change over between any two consecutive steps shall not exceed the average rate-of-change over the full enter service period.

- PGE requires there is a minimum delay to permit service to be set to 300 s followed by an active power ramp rate to be set to 300 seconds that adheres to the ramp characteristics described above.

D.7 Recommended Default Inverter Settings

There is one version of the default inverter settings. See Table 29 for these settings. A file including the settings in Table 29 can be found at the :
https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/PGE_IEEE-1547_DERSettings-_Final.csv

IMPORTANT: The nameplate parameters (parameters in the following tables starting with "NP_") are unique to each individual DER system's design. These were intentionally left blank as they will vary from system to system. The interconnection customers will provide all pertinent nameplate information to PGE at the time of application.

Table 29.Default Inverter Settings

Parameter	Value
MT_FILE_INFO_TYPE	SS
MT_UTILITY_NAME	Portland General Electric
MT_COUNTRY	United States of America

Parameter	Value
MT_DATE_OF_APPLICABILITY	8/15/2024
MT_NP_NORMAL_OP_CAT-APP	CAT_B
MT_NP_ABNORMAL_OP_CAT-APP	CAT_III
NP_P_MAX-SS	
NP_P_MAX_OVER_PF-SS	
NP_OVER_PF-SS	
NP_P_MAX_UNDER_PF-SS	
NP_UNDER_PF-SS	
NP_VA_MAX-SS	
NP_Q_MAX_INJ-SS	
NP_Q_MAX_ABS-SS	
NP_P_MAX_CHARGE-SS	
NP_APPARENT_POWER_CHARGE_MAX-SS	
NP_AC_V_NOM-SS	
AP_LIMIT_ ENABLE-SS	DISABLED
AP_LIMIT-SS	1
ES_PERMIT_SERVICE-SS	ENABLED
ES_V_LOW-SS	0.917
ES_V_HIGH-SS	1.05
ES_F_LOW-SS	59.5
ES_F_HIGH-SS	60.1
ES_DELAY-SS	300
ES_RANDOMIZED_DELAY-SS	0
ES_RAMP_RATE-SS	300
CONST_PF_MODE_ENABLE-SS	DISABLED
CONST_PF_EXCITATION-SS	ABS
CONST_PF-SS	1
CONST_Q_MODE_ENABLE-SS	DISABLED
CONST_Q-SS	0
QV_MODE_ENABLE-SS	ENABLED
QV_VREF-SS	1
QV_VREF_AUTO_MODE-SS	DISABLED
QV_VREF_TIME-SS	300
QV_CURVE_V2-SS	0.98
QV_CURVE_Q2-SS	0
QV_CURVE_V3-SS	1.02
QV_CURVE_Q3-SS	0
QV_CURVE_V1-SS	0.92
QV_CURVE_Q1-SS	0.44
QV_CURVE_V4-SS	1.08
QV_CURVE_Q4-SS	-0.44

Parameter	Value
QV_OLRT-SS	5
QP_MODE_ENABLE-SS	DISABLED
QP_CURVE_P3_GEN-SS	1
QP_CURVE_P2_GEN-SS	0.5
QP_CURVE_P1_GEN-SS	0.2
QP_CURVE_P1_LOAD-SS	-0.2
QP_CURVE_P2_LOAD-SS	-0.5
QP_CURVE_P3_LOAD-SS	-1
QP_CURVE_Q3_GEN-SS	-0.44
QP_CURVE_Q2_GEN-SS	0
QP_CURVE_Q1_GEN-SS	0
QP_CURVE_Q1_LOAD-SS	0
QP_CURVE_Q2_LOAD-SS	0
QP_CURVE_Q3_LOAD-SS	0.44
PV_MODE_ENABLE-SS	ENABLED
PV_CURVE_V1-SS	1.06
PV_CURVE_P1-SS	1
PV_CURVE_V2-SS	1.1
PV_CURVE_P2-SS	0
PV_OLRT-SS	10
OV2_TRIP_V-SS	1.2
OV2_TRIP_T-SS	0.16
OV1_TRIP_V-SS	1.1
OV1_TRIP_T-SS	13
UV1_TRIP_V-SS	0.88
UV1_TRIP_T-SS	21
UV2_TRIP_V-SS	0.5
UV2_TRIP_T-SS	2
OF2_TRIP_F-SS	62
OF2_TRIP_T-SS	0.16
OF1_TRIP_F-SS	61.2
OF1_TRIP_T-SS	300
UF1_TRIP_F-SS	58.5
UF1_TRIP_T-SS	300
UF2_TRIP_F-SS	56.5
UF2_TRIP_T-SS	0.16
PF_DBOF-SS	0.036
PF_DBUF-SS	0.036
PF_KOF-SS	0.05
PF_KUF-SS	0.05
PF_OLRT-SS	5

Parameter	Value
MC_HVRT_V1-SS	1.1
MC_LVRT_V1-SS	0.5

Appendix E Notification of Handbook Updates

Pursuant to OAR 860-082-0030(1)(b), those wishing to be notified of future updates to this Handbook can opt into PGE's notification list by following the instructions on PGE's OASIS page under the Generation Interconnection > Oregon Small Generator Interconnection > Distribution Interconnection Handbook folder. The current notification list is available in the same location.

16 Revision Table

Rev. No.	Revision Date	Reason for Revision	Affected Pages
0	7/1/2017	Initial release.	—
1	9/24/2021	Bring up to current standard. Setup online navigation.	ALL
1.1	11/4/2021	Added fillable fields and hyperlinks to pdf.	ALL
2	6/14/2024	Extensive changes to reflect OAR rule modifications.	ALL